Milagro Energy Inc.

ANNUAL REPORT 2003

straight to the point

CORPORATE PROFILE

Milagro Energy Inc. is engaged in the exploration, development and production of petroleum and natural gas reserves in western Canada. Focused full-cycle exploration combined with selected property acquisitions has resulted in a premium suite of assets. This disciplined approach has delivered year-over-year growth and has positioned Milagro for an exciting 2004.

Milagro trades on the Toronto Stock Exchange under the symbol "MIG". At December 31, 2003, there were 41,465,000 common shares outstanding.

INSIDE

ANNUAL GENERAL MEETING

The annual meeting of shareholders of Milagro Energy Inc. will be held on Thursday, June 10, 2004 at 10:00 a.m. in the Viking Room of the Calgary Petroleum Club at 319 – 5th Avenue S.W., Calgary, Alberta.

FINANCIAL AND OPERATING HIGHLIGHTS

	2003	2002	2001
Financial [(1)]			
($000s, except per share data)			
Oil and natural gas revenue	7,895	5,077	1,647
Cash flow from operations	3,095	2,455	566
Per share – diluted	0.10	0.13	0.04
Net earnings	502	611	35
Per share – diluted	0.02	0.03	–
Capital expenditures (net)	18,491	8,928	1,694
Debt and working capital	2,879	2,604	908
Shareholders' equity	23,026	8,023	3,542
Total assets	31,897	15,138	6,384
Operating			
Average daily production			
Oil (bbls per day)	292	235	205
Natural gas (mcf per day)	2,161	1,767	122
Equivalent barrels (boe per day)	652	530	225
Wells drilled			
Gross	18	24	6
Net	18.0	20.3	4.8

[(1)] Certain 2002 and 2001 amounts have been restated to reflect the retroactive application of adopting CICA handbook section 3110, "Asset Retirement Obligations" in 2003.

REPORT TO SHAREHOLDERS

Milagro is pleased to report its financial and operating results for the year ended December 31, 2003. During 2003 production grew by 23 percent to 653 barrels of oil equivalent (boe) per day; revenue increased 56 percent to $7,912,000; and capital expenditures rose 108 percent to $18.5 million. During the year the Company graduated from the TSX Venture Exchange and commenced trading on the Toronto Stock Exchange in October.

Profile

Milagro continues to implement its premium asset business model. We depend on full-cycle exploration to build core areas. The essential components for a core area are: geographic focus, operatorship, control of infrastructure, high working interests and long life reserves. An integral part of our business strategy involves developing successive core areas. Successful exploration programs become exploitation properties that in turn provide growth while we discover the next core area. We believe this strategy provides the Company with sustained growth through full-cycle exploration and the exploitation that follows.

Milagro strives to augment this strategy with strategic acquisitions. We pursue assets that will add development, exploitation and new exploration opportunities either within our existing core areas or as a potential starting point for new core areas.

Milagro's main area of focus is southwest Saskatchewan where the Company allocated 60 percent of its capital expenditures in 2003. The majority of the expenditures were at Battle Creek where Milagro combined the construction of a central oil battery and water disposal facility with an eight-well infill-drilling program in the Battle Creek West Madison oil pool. Results to date have been on target. This property will provide more growth during 2004 through additional infill drilling on the oil pool and continued development of our natural gas reserves in the Second White Specks and Milk River formations.

During 2003 Milagro proceeded with an aggressive exploration program in the Bittern Lake area in central Alberta where we allocated 30 percent of our capital expenditures. Resulting production from the area is modest. Natural gas exploration in the area during the year was disappointing. As a result the Company will monitor production from the area to determine whether more drilling is warranted in 2004. The Bittern Lake area is currently contributing 100 boe per day of light oil and natural gas production.

In west central Alberta the Judy Creek area is a new exploration concept that has potential to become a significant core area with drilling success. The area is identified as having significant liquids-rich natural gas potential. Milagro holds a 98 percent working interest in a large land block that we assembled during the year. The first exploration well was drilled, completed and tested during December 2003 and January 2004. While the production tests did not result in commercial quantities of natural gas, the test results did provide encouraging new data that will be used to further evaluate this potentially large play. This property is in the beginning stages of exploration and will require further drilling before it is properly evaluated. Milagro remains excited about the potential for this prospect.

New Equity

Milagro completed two private placements in 2003, raising a total of $15.87 million of new equity. In August the Company issued 10.8 million common shares at $0.80 per share for proceeds of $10.8 million. In October, Milagro completed a private placement for total proceeds of $5.07 million, consisting of 2.3 million flow-through shares at $1.30 per share and 2.0 million common shares at $1.04 per share.

Capital Expenditures

Capital expenditures were $18.5 million in 2003, versus $8.93 million during 2002. The Company's capital expenditures were allocated 39 percent to drilling and completions; 17 percent to well equipping and pipelines; 33 percent to facilities; 8.2 percent to exploratory mineral rights and lease retention; 2.6 percent to geological and geophysical; and 0.2 percent to other activities. During 2003 Milagro drilled 18 net wells and increased its net undeveloped land position to 47,100 acres from 20,800 acres.

Results

Milagro is a full-cycle exploration company. After new discoveries are made significant capital investment in infrastructure is required to develop the new reserves. During 2003 Milagro allocated 50 percent of its capital expenditures to infrastructure. These expenditures were required to continue development of Milagro's oil and natural gas properties in Alberta and Saskatchewan.

In 2003, Milagro concentrated its drilling efforts on new exploratory locations in Bittern Lake, with mixed results, and on development locations in Battle Creek that served to move reserves from the proved undeveloped category to the proved producing category.

Milagro's results this year were impacted by the implementation of new reserve reporting standards of disclosure for oil and natural gas activities pursuant to National Instrument 51-101. The negative reserve revisions for oil and natural gas were booked against properties in southwest Saskatchewan. For the most part, the higher certainty requirements of NI 51-101 resulted in reclassifications from probable reserves to possible reserves.

There were no new oil reserves booked for southwest Saskatchewan in 2003 because drilling in the area focused on proved non-producing oil reserves which are now categorized as proved producing. Natural gas additions in southwest Saskatchewan were attributable to the extension of an existing pool.

At central Alberta, where all of Milagro's reserves were found through the drill bit in 2003, limited production data and higher certainty requirements resulted in conservative reserve assignments.

The combination of the above resulted in a year of high capital expenditures with minimal reserve growth.

Outlook

Milagro has established a base case capital expenditure budget for 2004 of $6.0 million. These expenditures can be funded by cash flow and available bank debt. At the present time most of the expenditures are planned for southwest Saskatchewan. Drilling will commence in late spring/early summer, as soon as surface conditions permit. The expanded oil and natural gas facilities in southwest Saskatchewan make development drilling very attractive. The benefits of the capital expenditures on facilities in the fourth quarter of 2003 should be fully realized in 2004 and beyond.

Capital expenditures in central Alberta will depend on the performance of the wells placed on-stream in 2003.

In west central Alberta, Milagro remains committed to full-cycle exploration and the evaluation of its deep natural gas prospect. We are presently reviewing various options to test this play in 2004.

Milagro's 2004 base case capital expenditure program is expected to result in average production of 750-850 boe per day. We could undertake a larger capital expenditure program with additional equity. This would allow us to drill our significant inventory of development opportunities in the short term, resulting in a more rapid growth in the production base.

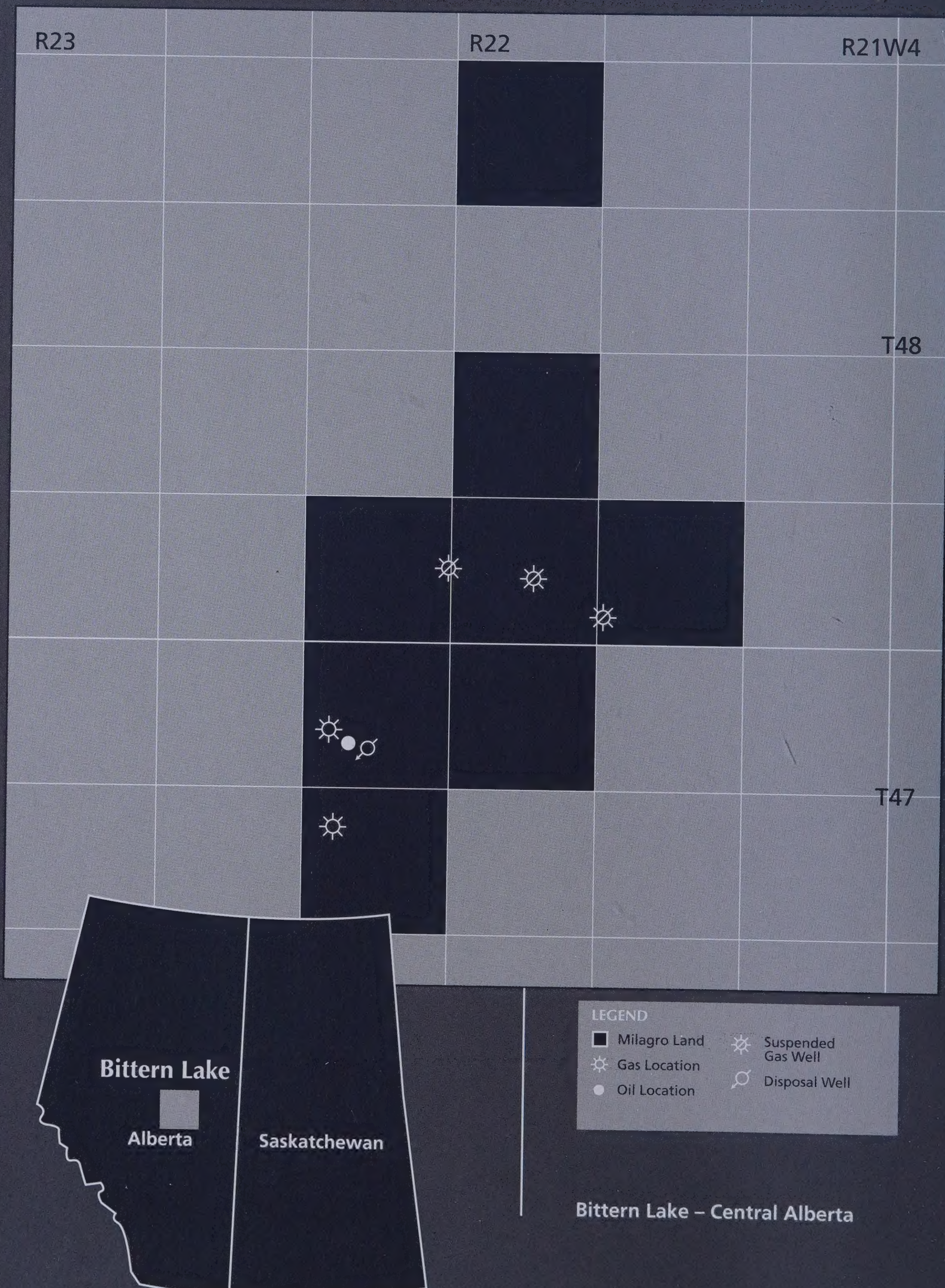
We acknowledge the efforts of the Milagro staff and also thank our shareholders and the Board of Directors for their continued support.

On behalf of the Board of Directors,

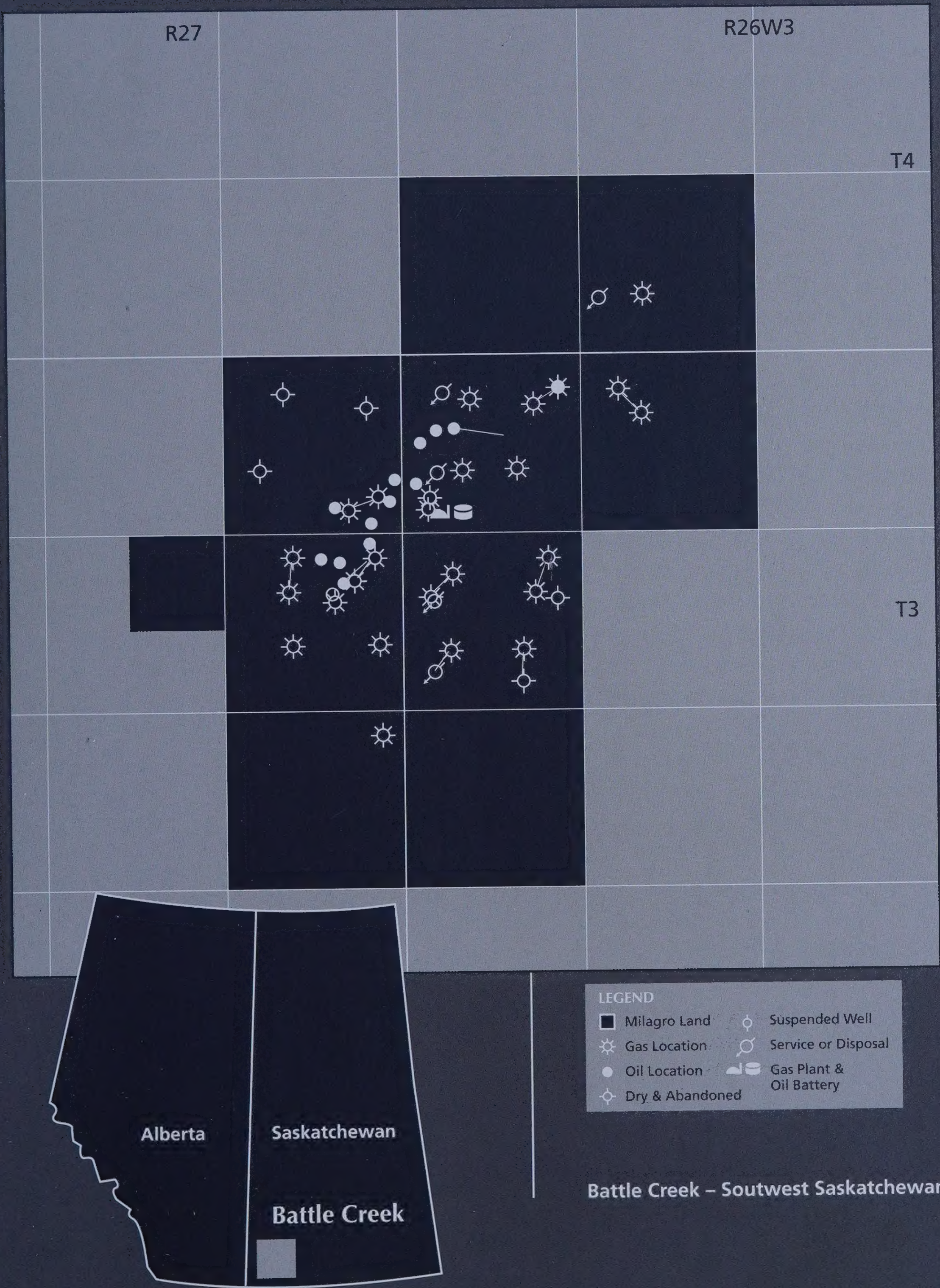
Jeffrey C. Rekunyk
President & C.E.O.
April 30, 2004

AREAS OF OPERATIONS

Judy Creek – West Central Alberta



Bittern Lake – Central Alberta



Battle Creek – Soutwest Saskatchewan

AIF (ANNUAL INFORMATION FORM)

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ABBREVIATIONS

Oil and Natural Gas Liquids

bbl	barrels
mbbl	thousand barrels
mmbbl	million barrels
bbl/d	barrels of oil per day
API	American Petroleum Institute
NGLs	natural gas liquids
stb	standard stock tank barrel
mstb	thousand standard stock tank barrels

Natural Gas

mcf	thousand cubic feet
mmcf	million cubic feet
mcf/d	thousand cubic feet per day
mmcf/d	million cubic feet per day
mmbtu	million British thermal units
GJ	gigajoule
GJ/d	gigajoules per day

Other

boe	barrel of oil equivalent converting six mcf of natural gas to one barrel of oil (6:1)
boe/d	barrels of oil equivalent per day
mboe	thousand of barrels of oil equivalent
M$	thousands of dollars
MM$	millions of dollars
NPV	net present value

CURRENCY

In this Annual Information Form, unless otherwise noted, all dollar amounts are expressed in Canadian dollars.

FORWARD-LOOKING STATEMENTS

Certain statements contained in this Annual Information Form and in certain documents incorporated by reference into this Annual Information Form, constitute forward-looking statements. These statements relate to future events or the Corporation's future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Corporation believes that the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form or as of the date specified in the documents incorporated by reference into this Annual Information Form, as the case may be. The Corporation does not intend, and does not assume any obligation, to update these forward-looking statements.

In particular, this Annual Information Form and the documents incorporated by reference contain forward-looking statements pertaining to the following:

- the quantity of reserves;
- oil and natural gas production levels;
- capital expenditure programs;
- projections of market prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the Corporation's ability to raise capital and to continually add to reserves through acquisitions and development; and
- treatment under government regulatory and taxation regimes.

The Corporation's actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Annual Information Form:

- volatility in market prices for oil and natural gas;
- liabilities and risks inherent in oil and natural gas operations;
- uncertainties associated with estimating reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions; and
- geological, technical, drilling and processing problems.

THE CORPORATION

Milagro Energy Inc. ("Milagro" or the "Corporation") was incorporated under the *Business Corporations Act* (Alberta) on December 17, 1998. The articles of the Corporation were amended by a Certificate of Amendment and Registration of Restated Articles dated January 18, 1999, which removed the private company restrictions and revised its share capital to consist of an unlimited number of common shares and an unlimited number of preferred shares. On July 27, 1999 the Corporation was amalgamated with Milagro Oil Limited under the Business Corporations Act (Alberta) (the "ABCA") and continued as one corporation under the name Milagro Energy Inc.

The head office of the Corporation is located at 1000, 633 – 6th Avenue SW, Calgary, Alberta, T2P 2Y5 and the registered office is located at 1000, 400 – 3rd Avenue SW, Calgary, Alberta T2P 4H2.

GENERAL DEVELOPMENT OF THE BUSINESS

Business of the Corporation

Milagro is a natural resource company actively involved in the acquisition, exploration, development and production of petroleum and natural gas reserves in Western Canada. See "Description of the Business".

Corporate Strategy

Milagro's goal is to continually increase value per share within pre-determined risk parameters. The business model to accomplish this uses full-cycle exploration and selective property acquisitions to build a premium suite of assets. The characteristics of these assets are geographic focus, operatorship, control of infrastructure, high working interests and long-life reserves.

History of the Corporation

Milagro became a reporting issuer as a Junior Capital Pool company in the Province of Alberta on April 22, 1999 by obtaining a receipt for a final prospectus dated April 19, 1999 from the Alberta Securities Commission. Pursuant to this prospectus, Milagro raised $300,000 by issuing 1,000,000 common shares at $0.30 per common share. The offering closed on May 18, 1999 and Milagro's common shares were listed on the Alberta Stock Exchange on June 1, 1999.

On July 27, 1999, the Corporation completed its major transaction when it amalgamated with Milagro Oil Limited, a private Alberta company. A total of 11,039,473 common shares were issued by the new entity to complete the amalgamation. As a result of the amalgamation, the Corporation held a working interest in six (3.0 net) oil wells and one water disposal well in the Battle Creek/Consul area of southwest Saskatchewan. Subsequent to the amalgamation, the Corporation participated in the drilling of two (1.0 net) horizontal wells and one (0.5 net) vertical well. In October 1999, Milagro completed a private placement of 953,676 flow-through common shares priced at $1.05 per share for proceeds of $1,001,356.

Production for the year ended December 31, 2000 averaged 112 barrels of oil per day. In 2000, Milagro completed a $3,404,000 capital expenditure program. During 2000, Milagro drilled two (1.3 net) wells resulting in one (1.0 net) oil well and one (0.3 net) dry hole. Milagro was active in the Battle Creek area of southwest Saskatchewan in 2000, closing an acquisition in June and completing an oil battery and water disposal system in November.

In September 2000, Milagro completed a private placement of 1,042,333 flow-through common shares priced at $0.48 per share for proceeds of $500,320.

Production averaged 225 boe per day during 2001, broken down as to 205 barrels of oil and 122 mcf of natural gas. Capital expenditures totalled $1,840,000 for the year, most of which was spent in southwest Saskatchewan. During 2001, Milagro drilled six (4.8 net) wells, resulting in five (4.7 net) natural gas wells and one (0.1 net) dry hole. In November 2001, the construction of a compression and dehydration facility was completed in southwest Saskatchewan and four gas wells were pipeline connected and placed on production.

During 2001, Milagro completed three financings which raised new equity of $1,937,000. In July, Milagro completed a private placement of 1,212,138 flow-through common shares and 606,069 common shares at a price of $0.50 per share for proceeds of $909,104. In November, a private placement of 600,000 units at a price of $0.40 per unit for proceeds of $240,000 was completed. Each unit was comprised of one common share and one common share purchase warrant exercisable at $0.45 per share. In December, Milagro completed a private placement of 750,000 flow-through common shares priced at $0.55 per share and 750,000 common shares priced at $0.50 per share for proceeds of $787,500.

In December 2001, Milagro changed its fiscal year end to December 31 from June 30, commencing with the six month period ending December 31, 2001. This change was made to facilitate the comparison of Milagro's financial and operating performance to other companies in its peer group.

Production averaged 530 boe per day during 2002, broken down as to 235 barrels of oil and 1,767 mcf of natural gas. During 2002, Milagro completed a $8,928,000 capital expenditure program. The Corporation drilled 24 (20.3 net) wells, resulting in 17 (14.5 net) natural gas wells, two (2.0 net) oil wells and five (3.8 net) abandonments. Capital investment for 2002 also included one property acquisition, the acquisition of 18,900 net acres of exploratory mineral rights and the upgrade of a natural gas compression facility in southwest Saskatchewan. Approximately 96 percent of 2002 capital expenditures were incurred in southwest Saskatchewan and the remainder in Alberta.

Milagro raised new equity of $5,108,000 during 2002 in three transactions. In June, 3,330,500 shares were issued at $0.75 per share for proceeds of $2,498,000. In November and December, 2,941,177 flow-through common shares were issued at $0.85 per share for proceeds of $2,500,000. Lastly, a total of 333,333 common shares were issued for proceeds of $110,000 on the exercise of stock options.

Average daily production in 2003 was 652 boe per day, broken down as to 292 barrels of oil and NGLs and 2,161 mcf of natural gas. During 2003, Milagro completed an $18.6 million capital expenditure program, allocated as follows: southwest Saskatchewan – $11.5 million; central Alberta – $5.7 million; west central Alberta – $1.2 million; and corporate $0.2 million. Notable expenditures included the drilling of 18 wells, the expansion of a natural gas compression and dehydration facility in southwest Saskatchewan, commencement of construction of a larger oil battery and water disposal system in southwest Saskatchewan, and the acquisition of 61 sections of new exploratory mineral rights. Capital expenditures were funded 82 percent through the issuance of new equity, 17 percent by cash flow from operations and 1 percent from changes working capital.

During 2003, Milagro issued a total of $16.3 million of new equity, primarily from two private placements. In August, 13.5 million common shares were issued at $0.80 per share for proceeds of $10.8 million. In October, 2.0 million common shares were issued at $1.04 per share and 2.3 million flow-through common shares were issued at $1.30 per share, for total proceeds of $5.1 million. In addition, 706,773 stock options were exercised for proceeds of $284,000 and 300,000 common share purchase warrants were exercised for proceeds of $135,000.

Environmental Matters

The oil and gas industry is subject to environmental regulations pursuant to applicable legislation. Such legislation provides for restrictions and prohibitions on release or emission of various substances produced in association with

certain oil and gas industry operations, and requires that well and facility sites be abandoned and reclaimed to the satisfaction of environmental authorities. As at December 31, 2003, Milagro recorded a provision on its balance sheet of $1,044,000 for asset retirement obligations for future site restoration. The Corporation maintains an insurance program consistent with industry practice to protect against losses due to accidental destruction of assets, well blowouts, pollution and other operating accidents or disruptions. The Corporation also has operational and emergency response procedures and safety and environmental programs in place to reduce potential loss exposure.

Employees

At December 31, 2003, Milagro's head office work force consisted of seven employees and two part time consultants. Field operations are provided by independent contractors.

Trends

There are a number of trends developing in the oil and gas industry which may have both a short term and long term effect on Milagro. There is a continuing trend relating to the level and volatility of oil and natural gas prices. Prices for both commodities have trended upwards and volatility has increased. Although oil prices are dependent on world events, natural gas prices react more to North American supply and demand factors.

The cyclical nature of the oil and gas industry is trending to shorter cycles, primarily as a result of commodity price volatility.

The consolidation of the oil and gas industry continues and recent transactions indicate that Canadian royalty income trusts are the dominant consolidator. As a result of natural decline rates and a relatively low cost of capital, most observers believe royalty income trusts will continue to be active asset gatherers. There is a continuing trend of mid-sized and larger oil and gas companies reorganizing into two new entities; a royalty income trust and an exploration and development company.

Royalty income trusts have had a significant impact on the oil and gas industry, including emerging and junior companies. Many junior exploration and development companies are staffed by personnel who were formerly employed by a company acquired by a trust. These experienced management teams often have pre-defined exit strategies that recognizes the growing royalty income trust sector.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Petroleum and Natural Gas Reserves

Gilbert Laustsen Jung Associates Ltd. ("GLJ"), independent petroleum engineers of Calgary, Alberta prepared a Reserves Assessment and Evaluation of Canadian Oil and Gas Properties – Corporate Summary dated March 18, 2004 and a corporate evaluation dated April 5, 2004 of Milagro's oil and gas reserves (collectively the "GLJ Report") which evaluations are both effective December 31, 2003. In preparing its report, GLJ obtained basic information from Milagro, which included land data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, capital budget forecasts, financial data and future operating plans. Other engineering, geological or economic data required to conduct the evaluation and upon which the GLJ Report is based, was obtained from public records, other operators and from GLJ's non-confidential files. The extent and character of ownership and the accuracy of all factual data supplied for the independent evaluation, from all sources, was accepted by GLJ as represented.

The following tables set forth certain information relating to the oil and natural gas reserves of the Corporation's properties and the present value of the estimated future net cash flow associated with such reserves as at December 31, 2003 which numbers may vary slightly from those presented in the GLJ Report due to rounding. Also due to rounding, certain columns may not add exactly. Certain tables which are derived by utilizing forecast prices and costs are presented with January 1, 2004 and April 1, 2004 pricing assumptions. The information set forth below is derived from the GLJ Report which have been prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in National Instrument 51-101 – Standards of Disclosure For Oil and Gas Activities ("NI 51-101"). All evaluations and reviews of future net cash flow are stated prior to any provision for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned. It should not be assumed that the estimated future net cash flow shown below is representative of the fair market value of the Corporation's properties. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, NGLs and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, NGLs and natural gas reserves may be greater than or less than the estimates provided herein.

In accordance with the requirements of NI 51-101, attached hereto are the following appendices:

Appendix A: Report on Reserves Data by Independent Qualified Reserves Evaluator in Form 51-101F2 which includes certain information estimated using forecast prices and costs based on January 1, 2004 pricing assumptions.

Appendix B: Report on Reserves Data by Independent Qualified Reserves Evaluator in Form 51-101F2 which includes certain information estimated using forecast prices and costs based on April 1, 2004 pricing assumptions.

Appendix C: Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3.

Definitions used for reserve categories in the GLJ Report are attached as Appendix D hereto.

Summary of Oil and Gas Reserves and Net Present Values of Future Net Revenue

As of December 31, 2003 (Constant Prices and Costs)

	Reserves					
	Light and Medium Oil		Natural Gas		Natural Gas Liquids	
Reserves Category	Gross (mbbl)	Net (mbbl)	Gross (mmcf)	Net (mmcf)	Gross (mbbl)	Net (mbbl)
Proved						
Developed producing	651	520	3,602	3,296	5	4
Developed non-producing	238	211	215	146	–	–
Undeveloped	299	262	1,204	1,146	–	–
Total proved	1,187	994	5,020	4,588	5	4
Probable	614	532	2,128	1,881	8	5
Total proved plus probable	1,801	1,526	7,148	6,469	13	9

Net Present Values of Future Net Revenue (Constant Prices and Costs)

	Before Income Taxes Discounted At (%/Year)					After Income Taxes Discounted At (%/Year)				
Reserves Category	0	5	10	15	20	0	5	10	15	20
	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)
Proved										
Developed producing	19,953	17,097	14,977	13,351	12,069	19,143	16,410	14,387	12,837	11,617
Developed non-producing	4,014	3,358	2,861	2,476	2,174	–	–	–	–	–
Undeveloped	6,363	5,012	4,023	3,280	2,710	–	–	–	–	–
Total proved	30,330	25,467	21,861	19,108	16,953	25,619	21,562	18,558	16,266	14,472
Probable	14,517	11,098	8,767	7,113	5,897	9,332	6,988	5,399	4,288	3,459
Total proved plus probable	44,847	36,564	30,628	26,221	22,849	34,951	28,550	23,957	20,544	17,931

Total Future Net Revenue (Undiscounted)

As of December 31, 2003 (Constant Prices and Costs)

Reserves Category	Revenue (M$)	Royalties (M$)	Oper. Costs (M$)	Dev. Costs (M$)	Well Aband. Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Income Taxes (M$)	Future Net Revenue After Income Taxes (M$)
Proved reserves	60,122	8,649	15,811	4,332	1,000	30,330	4,711	25,619
Proved plus probable reserves	88,537	12,496	23,047	6,952	1,195	44,847	9,896	34,951

Future Net Revenue by Production Group

As of December 31, 2003 (Constant Prices and Costs)

Reserves Category	Production Group	Future Net Revenue Before Income Taxes and ARTC (Discounted at 10%/Year) (M$)
Proved reserves	Light and medium crude oil (including solution gas and other by-products)	10,020
	Natural gas (including by-products but excluding solution gas from oil wells)	11,841
Proved plus probable reserves	Light and medium crude oil (including solution gas and other by-products)	14,489
	Natural gas (including by-products by excluding solution gas from oil wells)	16,139

Summary of Oil and Gas Reserves and Net Present Values of Future Net Revenue

As of December 31, 2003 (Forecast Prices and Costs)

(January 1, 2004 Pricing Assumptions)

	Reserves					
	Light and Medium Oil		Natural Gas		Natural Gas Liquids	
Reserves Category	Gross (mbbl)	Net (mbbl)	Gross (mmcf)	Net (mmcf)	Gross (mbbl)	Net (mbbl)
Proved						
Developed producing	629	510	3,559	3,259	5	4
Developed non-producing	210	188	215	149	–	–
Undeveloped	293	260	1,204	1,148	–	–
Total proved	1,132	958	4,978	4,555	5	4
Probable	608	534	2,108	1,869	8	5
Total proved plus probable	1,740	1,491	7,086	6,424	13	9

Net Present Values of Future Net Revenue (Forecast Prices and Costs)

(January 1, 2004 Pricing Assumptions)

	Before Income Taxes Discounted At (%/Year)					After Income Taxes Discounted At (%/Year)				
Reserves Category	0	5	10	15	20	0	5	10	15	20
	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)
Proved										
Developed producing	15,196	13,288	11,836	10,699	9,786	15,196	13,288	11,836	10,699	9,786
Developed non-producing	3,059	2,615	2,266	1,988	1,764	–	–	–	–	–
Undeveloped	4,348	3,411	2,715	2,186	1,776	–	–	–	–	–
Total proved	22,603	19,314	16,817	14,873	13,327	20,554	17,571	15,313	13,559	12,166
Probable	10,738	8,302	6,600	5,370	4,453	6,999	5,268	4,070	3,212	2,577
Total proved plus probable	33,342	27,615	23,417	20,243	17,780	27,553	22,839	19,383	16,771	14,743

Total Future Net Revenue (Undiscounted)

As of December 31, 2003 (Forecast Prices and Costs)

(January 1, 2004 Pricing Assumptions)

Reserves Category	Revenue (M$)	Royalties (M$)	Oper. Costs (M$)	Dev. Costs (M$)	Well Aband. Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Income Taxes (M$)	Future Net Revenue After Income Taxes (M$)
Proved reserves	50,577	7,032	15,449	4,353	1,140	22,603	2,049	20,554
Proved plus probable reserves	75,116	10,185	23,208	6,982	1,398	33,342	5,788	27,553

Future Net Revenue by Production Group

As of December 31, 2003 (Forecast Prices and Costs)

(January 1, 2004 Pricing Assumptions)

Reserves Category	Production Group	Future Net Revenue Before Income Taxes and ARTC (Discounted at 10%/Year) (M$)
Proved reserves	Light and medium crude oil (including solution gas and other by-products)	7,926
	Natural gas (including by-products but excluding solution gas from oil wells)	8,891
Proved plus probable reserves	Light and medium crude oil (including solution gas and other by-products)	11,366
	Natural gas (including by-products by excluding solution gas from oil wells)	12,051

Summary of Oil and Gas Reserves and Net Present Values of Future Net Revenue

As of December 31, 2003 (Forecast Prices and Costs)

(April 1, 2004 Pricing Assumptions)

	Reserves					
	Light and Medium Oil		Natural Gas		Natural Gas Liquids	
Reserves Category	Gross (mbbl)	Net (mbbl)	Gross (mmcf)	Net (mmcf)	Gross (mbbl)	Net (mbbl)
Proved						
Developed producing	629	503	3,559	3,258	5	4
Developed non-producing	210	186	215	148	–	–
Undeveloped	319	279	1,204	1,147	–	–
Total proved	1,158	968	4,978	4,552	5	4
Probable	582	505	2,140	1,899	8	5
Total proved plus probable	1,740	1,473	7,118	6,451	13	9

Net Present Values of Future Net Revenue (Forecast Prices and Costs)

(April 1, 2004 Pricing Assumptions)

	Before Income Taxes Discounted At (%/Year)					After Income Taxes Discounted At (%/Year)				
Reserves Category	0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)	0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)
Proved										
Developed producing	17,154	15,102	13,538	12,310	11,321	16,887	14,856	13,311	12,100	11,125
Developed non-producing	3,397	2,937	2,573	2,282	2,045	–	–	–	–	–
Undeveloped	5,051	4,075	3,342	2,779	2,339	–	–	–	–	–
Total proved	25,602	22,114	19,453	17,371	15,705	22,367	19,256	16,894	15,052	13,585
Probable	11,670	9,120	7,339	6,049	5,086	7,543	5,738	4,491	3,597	2,934
Total proved plus probable	37,272	31,234	26,792	23,420	20,791	29,910	24,994	21,385	18,649	16,519

PRICING ASSUMPTIONS

Constant Prices and Costs – December 31, 2003

GLJ employed the following pricing, exchange rate and inflation rate assumptions as of December 31, 2003 in estimating Milagro's reserves data using constant prices and costs.

	Oil			Natural Gas		
	WTI $US/bbl	Edmonton $Cdn/bbl	Corporate Average $Cdn/bbl	AECO-C $/mmbtu	Corporate Average $Cdn/bbl	Exchange $US/$Cdn
December 31, 2003	32.52	40.81	25.69	6.09	5.85	0.75

Forecast Prices and Costs – January 1, 2004

GLJ employed the following pricing, exchange rate and inflation rate assumptions in estimating Milagro's reserves data using forecast prices and costs as of January 1, 2004.

Consultants Average (2004-01)

Price Forecasts

Effective January 1, 2004

			Light Crude Oil		Natural Gas Liquids at Edmonton		
Year	Exchange Rate $US/$Cdn	Inflation %	WTI Cushing Oklahoma $US/bbl	Edmonton Par Price 40° API $/bbl	Propane $/bbl	Butane $/bbl	Pentanes Plus $/bbl
2003	0.7213	2.8	31.07	43.66	33.03	33.93	44.01
Forecast							
2004	0.7500	0.0	29.21	37.81	26.80	28.27	38.54
2005	0.7500	1.67	26.43	34.10	22.64	23.96	34.80
2006	0.7500	1.67	25.42	32.79	21.16	22.53	33.48
2007	0.7500	1.67	25.38	32.72	21.03	22.48	33.42
2008	0.7500	1.67	25.51	32.89	21.03	22.59	33.60
2009	0.7500	1.67	25.81	33.26	21.24	22.85	33.98
2010	0.7500	1.67	26.11	33.63	21.42	23.10	34.36
2011	0.7500	1.67	26.42	34.04	21.69	23.36	34.78
2012	0.7500	1.67	26.72	34.42	21.94	23.62	35.17
2013	0.7500	1.67	27.03	34.83	22.22	23.92	35.59
2014	0.7500	1.67	27.37	35.25	22.50	24.21	36.02
2015	0.7500	1.67	27.88	35.87	22.87	24.59	36.65
2016	0.7500	1.67	28.40	36.49	23.23	24.98	37.28
2017	0.7500	1.67	28.91	37.12	23.60	25.39	37.92
2018	0.7500	1.67	29.43	37.71	23.94	25.75	38.52
Thereafter	0.7500	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%

Consultants Average (2004-01) *(continued)*

Price Forecasts

Effective January 1, 2004

	Henry Hub $US/mmbtu	Alberta Spot @ AECO-C $Cdn/mmbtu	Alberta Governmental Reference Price Plant-gate $Cdn/mmbtu	Alberta Spot Plant-gate $Cdn/mmbtu	BC Spot Plant-gate $Cdn/mmbtu	Canwest Plant-gate $Cdn/mmbtu
Year						
2004	5.14	5.90	5.65	5.69	5.60	5.13
2005	4.65	5.33	5.10	5.12	5.10	4.64
2006	4.35	4.98	4.76	4.76	4.85	4.38
2007	4.30	4.95	4.74	4.74	4.75	4.35
2008	4.28	4.92	4.72	4.72	4.68	4.33
2009	4.31	4.96	4.76	4.76	4.70	4.35
2010	4.35	5.00	4.79	4.79	4.70	4.38
2011	4.40	5.06	4.85	4.85	4.75	4.45
2012	4.45	5.12	4.91	4.91	4.80	4.51
2013	4.50	5.19	4.98	4.98	4.85	4.58
2014	4.55	5.25	5.05	5.05	4.90	4.64
2015	4.62	5.36	5.13	5.13	4.98	4.72
2016	4.70	5.46	5.20	5.20	5.05	4.80
2017	4.77	5.56	5.28	5.28	5.13	4.86
2018	4.84	5.66	5.36	5.36	5.20	4.93
Thereafter	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%

Notes:

Price forecasts used to generate the above projections:

Gilbert Laustsen Jung Associates Ltd. and two other independent petroleum engineering firms – Effective January 1, 2004.

Note: Effective October 2003, the BC Spot Plant-gate is an average of GLJ's and one other independent petroleum engineering firm's prices only.

Forecast Prices and Costs – April 1, 2004

GLJ employed the following pricing, exchange rate and inflation rate assumptions estimating Milagro's reserves using Forecast prices and costs as of April 1, 2004.

Forecast Prices Used in Preparing Reserves Data

Gilbert Laustsen Jung Associates Ltd.

Crude Oil and Natural Gas Liquids

Price Forecast

Effective April 1, 2004

Year	Inflation %	Bank of Canada Avg. Noon Exchange Rate $US/$Cdn	West Texas Intermediate Crude Oil at Cushing Oklahoma Constant 2004 $ $US/bbl	West Texas Intermediate Crude Oil at Cushing Oklahoma Then Current $US/bbl	Light, Sweet Crude Oil (40° API, 0.3%S) at Edmonton Constant 2004 $ $Cdn/bbl	Light, Sweet Crude Oil (40° API, 0.3%S) at Edmonton Then Current $Cdn/bbl	Bow River Crude Oil Stream Quality at Hardisty Constant 2004 $ $Cdn/bbl	Bow River Crude Oil Stream Quality at Hardisty Then Current $Cdn/bbl	Heavy Crude Oil Proxy (12° API) at Hardisty Constant 2004 $ $Cdn/bbl	Heavy Crude Oil Proxy (12° API) at Hardisty Then Current $Cdn/bbl	Medium Crude Oil (29° API, 2.0%S) at Cromer Constant 2004 $ $Cdn/bbl	Medium Crude Oil (29° API, 2.0%S) at Cromer Then Current $Cdn/bbl	Alberta Natural Gas Liquids (Then Current Dollars) Spec Ethane $Cdn/bbl	Alberta Natural Gas Liquids (Then Current Dollars) Edmonton Propane $Cdn/bbl	Alberta Natural Gas Liquids (Then Current Dollars) Edmonton Butane $Cdn/bbl	Alberta Natural Gas Liquids (Then Current Dollars) Edmonton Pentanes Plus $Cdn/bbl
1993	1.8	0.775	22.56	18.46	26.81	21.94	20.44	16.73	16.20	13.26	21.49	17.59	n/a	14.10	13.64	21.17
1994	0.2	0,732	20.62	17.18	26.67	22.22	22.17	18.47	18.03	15.02	23.17	19.30	n/a	12.53	13.45	21.69
1995	2.2	0.729	22.03	18.39	29.03	24.23	24.92	20.80	20.70	17.28	25.98	21.69	n/a	13.90	13.79	24.11
1996	1.6	0.733	25.78	21.99	34.46	29.39	29.47	25.13	23.52	20.06	30.60	26.10	n/a	22.31	17.15	30.06
1997	1.6	0.722	23.79	20.61	32.14	27.85	24.43	21.17	16.63	14.41	27.37	23.72	n/a	18.62	18.73	30.91
1998	0.9	0.675	16.38	14.42	23.13	20.36	16.63	14.64	10.73	9.45	19.25	16.95	n/a	11.15	12.44	21.83
1999	1.7	0.673	21.72	19.29	31.17	27.69	26.84	23.84	22.14	19.67	28.62	25.42	n/a	15.89	18.70	27.71
2000	2.7	0.673	33.45	30.22	49.33	44.56	39.02	35.25	30.26	27.34	44.18	39.91	n/a	32.18	35.60	46.31
2001	2.6	0.646	27.99	25.97	42.47	39.40	29.86	27.70	18.26	16.94	34.02	31.56	n/a	31.85	31.17	42.48
2002	2.2	0.637	27.40	26.08	42.37	40.33	33.44	31.83	27.91	26.57	37.27	35.48	n/a	21.39	27.08	40.73
2003	2.8	0.721	31.93	31.07	44.88	43.66	33.01	32.11	26.99	26.26	38.60	37.55	n/a	32.14	34.36	44.23
2004 Q1(E)	1.5	0.757	34.50	34.50	44.50	44.50	34.25	34.25	28.00	28.00	40.50	40.50	n/a	33.50	36.50	45.00
2004 Q2	1.5	0.750	36.00	36.00	47.25	47.25	37.75	37.75	31.75	31.75	43.75	43.75	22.00	36.25	39.25	47.75
2004 Q3	1.5	0.750	34.00	34.00	44.50	44.50	35.25	35.25	29.50	29.50	41.00	41.00	22.25	33.50	36.50	45.00
2004 Q4	1.5	0.750	32.75	32.75	43.00	43.00	32.50	32.50	26.25	26.25	39.00	39.00	23.25	32.00	35.00	43.50
2004 Full Yr.	1.5	0.750	34.25	34.25	44.75	44.75	35.00	35.00	29.00	29.00	41.00	41.00	22.50	33.75	36.75	45.25
2004 Q2-Q4	0.0	0.750	34.25	34.25	44.75	44.75	35.00	35.00	29.00	29.00	41.00	41.00	22.50	33.75	36.75	45.25
2005	1.5	0.750	28.50	29.00	37.25	37.75	29.75	30.25	24.75	25.00	33.25	33.75	18.50	25.75	28.75	38.25
2006	1.5	0.750	26.25	27.00	34.25	35.25	28.00	28.75	23.00	23.75	30.25	31.25	17.25	23.25	25.25	35.75
2007	1.5	0.750	24.00	25.00	31.00	32.50	24.75	26.00	20.00	21.00	27.25	28.50	16.50	20.50	22.50	33.00
2008	1.5	0.750	23.50	25.00	30.50	32.50	24.50	26.00	19.75	21.00	26.75	28.50	16.50	20.50	22.50	33.00
2009	1.5	0.750	23.25	25.00	30.25	32.50	24.25	26.00	19.50	21.00	26.50	28.50	16.50	20.50	22.50	33.00
2010	1.5	0.750	23.25	25.50	30.25	33.00	24.25	26.50	19.75	21.50	26.50	29.00	17.00	21.00	23.00	33.50
2011	1.5	0.750	23.25	25.75	30.25	33.50	24.25	27.00	19.75	22.00	26.50	29.50	17.25	21.50	23.50	34.00
2012	1.5	0.750	23.25	26.25	30.25	34.00	24.50	27.50	20.00	22.50	26.75	30.00	17.50	21.75	24.00	34.50
2013	1.5	0.750	23.25	26.50	30.25	34.50	24.50	28.00	20.00	23.00	26.75	30.50	18.00	22.00	24.50	35.00
2014	1.5	0.750	23.25	27.00	30.25	35.00	24.50	28.50	20.25	23.50	26.75	31.00	18.00	22.50	24.75	35.50
2015+	1.5	0.750	23.25+1.5%/yr		30.25+1.5%/yr		24.50+1.5%/yr		20.25+1.5%/yr		26.75+1.5%/yr			Escalate at 1.5% per year		

Forecast Prices Used In Preparing Reserves Data

Gilbert Laustsen Jung Associates Ltd.

Natural Gas and Sulphur

Price Forecast

Effective April 1, 2004

	US Gulf Coast Gas Price @ Henry Hub		Midwest Price @ Chicago	AECO-C Spot	Alberta Plant-gate					Saskatchewan Plant-gate	
					Spot						
	Constant 2004 $	Then Current	Then Current	Then Current	Constant 2004 $	Then Current	ARP	Aggregator	Alliance	Energy	Sask. Spot
Year	$US/ mmbtu	$US/ mmbtu	$US/ mmbtu	$Cdn/ mmbtu	$/ mmbtu	$/ mmbtu	$/ mmbtu	$/ mmbtu	$/ mmbtu	$/ mmbtu	$/ mmbtu
1993	2.58	2.11	2.31	2.26	2.64	2.16	1.71	n/a	n/a	1.48	2.07
1994	2.33	1.94	2.11	1.98	2.23	1.86	1.81	n/a	n/a	1.88	1.87
1995	2.04	1.70	1.69	1.15	1.22	1.02	1.31	n/a	n/a	1.35	0.98
1996	2.95	2.52	2.73	1.39	1.48	1.26	1.63	n/a	n/a	1.52	1.28
1997	2.85	2.47	2.75	1.84	1.95	1.69	1.96	n/a	n/a	1.84	1.74
1998	2.45	2.16	2.20	2.03	2.14	1.88	1.94	n/a	n/a	2.05	2.13
1999	2.61	2.32	2.34	2.92	3.10	2.75	2.48	n/a	n/a	2.83	2.97
2000	4.79	4.33	4.38	5.08	5.45	4.92	4.50	4.60	n/a	4.79	5.16
2001	4.37	4.05	4.17	6.21	6.54	6.07	5.41	5.30	5.61	5.71	6.20
2002	3.53	3.36	3.30	4.04	4.08	3.88	3.88	3.83	3.82	4.04	4.08
2003	5.65	5.50	5.60	6.66	6.67	6.49	6.13	5.89	6.69	6.40	6.68
2004 Q1 (E)	5.70	5.70	5.85	6.55	6.30	6.30	6.20	5.90	6.30	6.35	6.45
2004 Q2	5.60	5.60	5.65	6.55	6.30	6.30	6.20	5.90	6.15	6.35	6.45
2004 Q3	5.70	5.70	5.75	6.65	6.40	6.40	6.30	6.00	6.20	6.45	6.55
2004 Q4	5.85	8.85	6.00	6.90	6.65	6.65	6.55	6.20	6.55	6.70	6.80
2004 Full Yr.	5.70	5.70	5.80	6.65	6.40	6.40	6.30	6.00	6.30	6.45	6.55
2004 Q2-Q4	5.70	5.70	5.80	6.70	6.45	6.45	6.35	6.05	6.35	6.50	6.60
2005	4.75	4.80	5.00	5.55	5.20	5.30	5.25	5.15	5.30	5.40	5.45
2006	4.35	4.50	4.75	5.20	4.80	4.95	4.95	4.95	4.95	5.10	5.10
2007	4.15	4.35	4.60	5.00	4.55	4.75	4.75	4.75	4.75	4.90	4.90
2008	4.10	4.35	4.60	5.00	4.50	4.75	4.75	4.75	4.75	4.90	4.90
2009	4.05	4.35	4.60	5.00	4.45	4.75	4.75	4.75	4.75	4.90	4.90
2010	4.05	4.40	4.65	5.10	4.45	4.85	4.85	4.85	4.85	5.00	5.00
2011	4.05	4.50	4.75	5.20	4.45	4.95	4.95	4.95	4.95	5.10	5.10
2012	4.05	4.55	4.80	5.25	4.45	5.05	5.05	5.05	5.05	5.20	5.15
2013	4.05	4.60	4.90	5.35	4.50	5.15	5.15	5.15	5.15	5.30	5.25
2014	4.05	4.70	4.95	5.45	4.50	5.20	5.20	5.20	5.20	5.35	5.35
2015+	4.05	+1.5%/yr	+1.5%/yr	+1.5%/yr	4.50	+1.5%/yr				Escalate at +1.5%/yr	

Unless otherwise stated, the gas price reference point is the receipt point on the applicable provincial gas transmission system known as the plant-gate.

The plant-gate price represents the price before raw gas gathering and processing charges are deducted.

Spot refers to weighted average one month price.

Milagro's weighted average realized sales prices for the year ended December 31, 2003 were $29.26/bbl for crude oil, $6.06/mcf for natural gas and $26.68/bbl for NGLs.

RECONCILIATION OF CHANGES IN RESERVES AND FUTURE NET REVENUE

Reserves Reconciliation

The following table sets forth a reconciliation of Milagro's total net proved, probable and proved plus probable reserves as at December 31, 2003 against such reserves as at December 31, 2002 based on forecast price and cost assumptions.

	Light and Medium Oil			Associated and Non-Associated Gas			Natural Gas Liquids		
Factors	Net Proved (mbbl)	Net Probable (mbbl)	Net Proved Plus Probable (mbbl)	Net Proved (mmcf)	Net Probable (mmcf)	Net Proved Plus Probable (mmcf)	Net Proved (mbbl)	Net Probable (mbbl)	Net Proved Plus Probable (mbbl)
December 31, 2002	1,014	797	1,811	6,209	1,667	7,876	–	–	–
Extensions	36	4	40	443	677	1,120	5	5	10
Improved recovery	–	–	–	–	–	–	–	–	–
Technical revisions	19	(273)	(253)	(1,353)	(432)	(1,785)	–	–	–
Discoveries	–	–	–	–	–	–	–	–	–
Acquisitions	–	–	–	–	–	–	–	–	–
Dispositions	–	–	–	–	–	–	–	–	–
Economic factors	(26)	5	(21)	(11)	(43)	54	–	–	–
Production	(86)	–	(86)	(733)		(733)	(1)	–	(1)
December 31, 2003	958	533	1,491	4,555	1,869	6,424	4	5	9

Notes:

(1) At December 31, 2002, probable reserves are risked at 50%.

(2) The forecast prices and costs for the December 31, 2003 data was derived using January 1, 2004 pricing assumptions.

Future Net Revenue Reconciliation

The following table sets forth a reconciliation of Milagro's estimate of future net revenue discounted at 10%, attributable to net proved reserves as evaluated on the GLJ Report using constant prices and costs.

Period and Factor	After Tax 2003 (M$)	Before Tax 2003 (M$)
December 31, 2002	19,302	29,576
Sales and transfers of oil and gas produced during the period net of production costs and royalties (1)	(4,467)	(4,467)
Net change in sales and transfer prices and in production costs and royalties related to future production (2)	(6,629)	(6,629)
Changes in previously estimated future development costs incurred during the period (3)	16,995	16,995
Changes in estimated future development costs (4)	(12,160)	(12,160)
Net change resulting from extensions and improved recovery (5)	1,205	1,205
Net change resulting from discoveries (5)	–	–
Changes resulting from acquisitions of reserves (5)	–	–
Changes resulting from dispositions of reserves (5)	–	–
Net change resulting from revisions in quantity estimates	(3,189)	(3,189)
Accretion of discount (6)	2,958	2,958
Net change in income taxes (7)	6,971	–
Other significant factors (8)	(2,428)	(2,428)
December 31, 2003	18,558	21,861

Notes:

(1) Company actual before income taxes, excluding G&A.

(2) The impact of changes in prices and other economic factors on future net revenue.

(3) Actual capital expenditures relating to the exploration, development and production of oil and gas reserves.

(4) The change in forecast development costs.

(5) End of period net present value of the related reserves.

(6) Estimated as 10% of the beginning of period net present value.

(7) The difference between forecast income taxes at beginning of period and the actual taxes for the period plus forecast income taxes at the end of period.

(8) Includes changes due to revised production profiles, development timing, operating costs, royalty rates, actual price received in 2003 versus forecast, etc.

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

The following discussion generally describes the basis on which Milagro attributes proved and probable undeveloped reserves and its plans for developing those undeveloped reserves.

Proved Undeveloped Reserves

Proved undeveloped reserves are generally those reserves related to wells that have been tested and not yet tied-in, wells drilled near the end of the fiscal year or wells further away from Milagro gathering systems. In addition, such reserves may relate to planned infill drilling locations. The majority of these reserves are planned to be on stream within a two year timeframe.

Probable Undeveloped Reserves

Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. The majority of these reserves are planned to be on stream within a two year timeframe.

Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, commodity prices and economic conditions. Milagro's reserves are evaluated by GLJ, an independent engineering firm.

Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, commodity prices, economic conditions and governmental restrictions. Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. Milagro's actual production, revenues, taxes, development and operating expenditures with respect to its reserves may vary from such estimates, and such variances could be material.

Future Development Costs

The following table outlines development costs deducted in the estimation of future net revenue attributable to proved reserves (using both constant prices and costs and forecast prices and costs) and proved plus probable reserves (using forecast prices and costs only).

	Constant Prices and Costs	Forecast Prices and Costs (January 1, 2004 Pricing Assumptions)	
	Proved Reserves (M$)	Proved Reserves (M$)	Proved Plus Probable Reserves (M$)
2004	3,213	3,213	5,183
2005	1,069	1,085	1,745
2006	0	0	0
2007	0	0	0
2008	0	0	0
Remaining years	50	55	55
Total undiscounted	4,332	4,353	6,983
Total discounted at 10% per year	4,017	4,033	6,484

The Corporation has established a $6 million capital program to fund its exploration and development activities for 2004. The Corporation's capital program does not include any acquisition opportunities, which would likely be financed through debt or equity financings.

Milagro estimates that its internally generated cash flow will be sufficient to fund the future development costs disclosed above. Milagro typically has available three sources of funding to finance its capital expenditure program; internally generated cash flow from operations, debt financing when appropriate and new equity issues, if available on favourable terms.

OTHER OIL AND GAS INFORMATION

Oil and Gas Properties and Wells

Milagro has three core areas; southwest Saskatchewan, central Alberta and west central Alberta. The Corporation acquired its initial interest in southwest Saskatchewan as a result of the amalgamation with Milagro Oil Limited in 1999. Milagro acquired its initial interest in central Alberta in late 2002 and drilled its first well in the area in early 2003. Milagro acquired its initial interests in west central Alberta in the fall of 2002 and drilled its first well in the area December 2003/January 2004.

All of Milagro's 2003 production and all of the Corporation's December 31, 2003 oil and natural gas reserves are attributable to the southwest Saskatchewan and central Alberta core areas.

Southwest Saskatchewan

Milagro's Saskatchewan assets are located in the southwest corner of the province near Battle Creek. Most of the region is easily accessible by road and sparsely populated. Milagro produces oil and natural gas in the area from a total of four productive horizons. Oil is produced from the Upper Shaunavon Formation (1,300 metres deep) and the Madison Formation (1,400 metres deep) and natural gas is produced from the Second White Specks Formation (850 metres deep) and the Milk River Formation (650 metres deep). During 2003, Milagro drilled 11 wells in the area, resulting in six oil wells, three gas wells and two service wells. Capital expenditures in the area also included the acquisition of 12 sections of exploratory acreage and the expansion of compression, dehydration and production facilities.

In the fall of 2003, Milagro started construction of a new oil battery and water disposal facility in southwest Saskatchewan. The new facility is capable of handling 36,000 barrels of fluid per day and replaced two small batteries. Completion of the new facility in March 2004 will allow Milagro to start the second phase of its oil exploitation program without fluid handling restrictions.

Central Alberta

Milagro's central Alberta assets are situated approximately 30 miles southeast of Edmonton, near Bittern Lake. During 2003, Milagro shot eight square kilometers of 3D seismic, drilled six wells, re-entered 1 well and built an oil production facility.

Five wells were drilled to the base of the Mannville formation targeting natural gas. Two of the five wells are producing; one (the discovery well) from the Glauconite formation; the other from the Belly River. A third well initially produced at strong rates from the Ellerslie formation but became uneconomic due to flank or lateral water invasion. The remaining two gas targets have Belly River potential but are not tied-in. In early 2004, Milagro installed a small compressor in central Alberta to maximize natural gas production.

Central Alberta drilling included one oil target in 2003, which was converted to a water disposal well. In August, an existing well bore was successfully re-completed for Ellerslie oil production. The well was not placed on production until late November due to delays in the regulatory approval for the water disposal well.

West Central Alberta

The west central Alberta prospect area is located 75 miles northwest of Edmonton, near Judy Creek. This exploration project is targeting high heating value natural gas from a deep, high-pressure reservoir.

During 2003, Milagro acquired an average 98% working interest in 50 contiguous sections of land in the area, primarily for the deeper horizons. In late December 2003, Milagro spud an exploratory well on the southwest corner of the block. The well was completed in the Gilwood formation (2,500 metres) in January 2004 and flowed significant natural gas before down-dip water rendered the well uneconomic. The well was abandoned in March 2004. The test data gathered from the completion confirmed economic rates of gas from the reservoir and the pressure data supports the potential for a gas column up dip of this location. Ninety-five percent of Milagro's lands are up dip of the first well.

Wells

As at December 31, 2003, the Corporation had an interest in 40 gross (37.5 net) producing and 4 gross (4 net) non-producing oil and natural gas wells as follows.

	Producing				Non-Producing			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross [1]	Net [2]	Gross	Net	Gross	Net	Gross	Net
Wells								
Alberta	1.0	1.0	2.0	2.0	–	–	3.0	3.0
Saskatchewan	12.0	12.0	25.0	22.5	–	–	1.0	1.0
Total	13.0	13.0	27.0	24.5	–	–	4.0	4.0

Notes:

(1) "Gross" wells means the number of wells in which Milagro has a working interest or a royalty interest that may be convertible to a working interest.

(2) "Net" wells means the aggregate number of wells obtained by multiplying each gross well by Milagro's percentage working interest therein.

Properties With No Attributed Reserves

The following table sets forth the gross and net acres of unproved properties held by the Corporation and the net area of unproved property for which the Corporation expects its rights to explore, develop and exploit to expire during the next year.

	Unproved Properties (acres)		
Location	Gross [1]	Net [2]	Net Area to Expire in 2004
Alberta	31,840	31,227	843
Saskatchewan	15,873	15,873	–
Total	47,713	47,100	843

Notes:

(1) "Gross Acres" are the total acres in which Milagro has or had an interest.

(2) "Net Acres" is the aggregate of the total acres in which Milagro has or had an interest multiplied by Milagro's working interest percentage held therein.

There are no costs or work commitments associated with Milagro's non-producing properties except for a recompletion obligation on its lands in southwest Saskatchewan involving 5,120 net acres, which obligation will be completed by June 30, 2004, to ensure this land block continues.

Forward Contracts

Milagro may use certain financial instruments to hedge its exposure to commodity price fluctuations on a portion of its crude oil and natural gas production. Milagro currently has no hedges in place.

Additional Information Concerning Abandonment and Reclamation Costs

Milagro estimates well abandonment and reclamation costs for surface leases, wells and facilities based on its previous experience, current regulations, costs, technology and industry standards area by area. Such costs are included in the GLJ Report as deductions in arriving at future net revenue. The expected total abandonment costs for 47.5 net wells (including producing, non-producing and service wells) and for four gross/net facilities are summarized net of estimated salvage value, calculated without discount and using a discount rate of 10% is as follows:

	Constant Pricing		Forecast Pricing			
	Proved NPV 0%	Proved NPV 10%	Proved NPV 0%	Proved NPV 10%	Proved Plus Probable NPV 0%	Proved Plus Probable NPV 10%
Wells with reserves assigned	1,000	400	1,140	487	1,398	510
Wells and facilities with no reserves assigned	738	288	871	324	871	324
Total abandonment and reclamation cost provision	1,738	688	2,011	811	2,269	834
Portion forecast to be paid during the next three years	155	139	157	141	157	141

Income Tax Horizon

At the end of 2003, Milagro had estimated income tax deductions of approximately $20.6 million available to reduce future taxable income. Milagro does not expect to incur current income taxes in 2004.

Costs Incurred

The following table summarizes Milagro's property acquisition costs, exploration costs and development costs (before property dispositions and corporate asset additions) incurred during the financial year ended December 31, 2003.

Property Acquisitions and Capital Expenditures

Nature of Cost	Amount (M$)
Property acquisition costs	
Proved	–
Unproved	1,526
Exploration costs	3,428
Development costs	13,657
Total	18,611

Exploration and Development Activities

The following table summaries the results of exploration and development activities during the financial year ended December 31, 2003.

	Gross	Net
Development Wells		
Gas	2.0	2.0
Oil	6.0	6.0
Service	3.0	3.0
Dry	–	–
Exploratory Wells		
Gas	6.0	6.0
Oil	–	–
Service	–	–
Dry	1.0	1.0
Total Wells	18.0	18.0

Milagro's initial plans for 2004 include a $6.0 million capital expenditure program, funded from cash flow from operations and bank debt. Most of the expenditures are targeted for southwest Saskatchewan, where Milagro has an inventory of lower risk oil and natural gas locations to drill. Drilling in central Alberta will depend somewhat on the performance of wells placed on production in 2003. Milagro is reviewing various options to continue testing the deep gas play in west central Alberta in 2004.

Production Estimates

The following discloses the estimated average daily production of Milagro by 2004 by product type associated with the first year of the future net revenue estimates reported in the GLJ Report effective December 31, 2003.

	Light and Medium Crude Oil (bbl/d)	Natural Gas (mcf/d)	Natural Gas Liquids (bbl/d)	BOE (boe/d)
Corporation				
Proved	–	–	–	–
Developed producing	436	1,780	5	737
Developed non-producing	89	126	–	110
Undeveloped	184	278	–	230
Total proved	709	2,184	5	1,077
Probable	89	576	4	189
Total proved plus probable	798	2,760	9	1,267
Southwest Saskatchewan				
Proved	–	–	–	–
Developed producing	411	1,448	–	652
Developed non-producing	89	126	–	110
Undeveloped	184	278	–	230
Total proved	684	1,852	–	993
Probable	89	181	–	119
Total proved plus probable	773	2,033	–	1,112

Production History

The following table summarizes Milagro's average daily production before deduction of royalties, for the periods indicated.

	2003				
	Year	Q4	Q3	Q2	Q1
Oil (bbl/d)[1]	292	339	242	271	314
Natural gas (mcf/d)	2,161	2,015	2,198	1,936	2,498
Total (boe/d)	652	675	608	594	730

Note:

(1) Includes a negligible amount of NGLs.

Netback History

The following table sets forth information respecting average net product prices received, royalties paid, operating expenses and netbacks received by the Corporation in respect of the Corporation's production of crude oil and natural gas for the periods indicated.

	2003				
	Year	Q4	Q3	Q2	Q1
Selling prices (1)					
Oil ($/bbl) (2)	29.24	25.25	27.28	28.05	36.22
Natural gas ($/mcf)	6.06	5.63	5.90	5.86	6.72
Royalties					
Oil ($/bbl) (2)	(8.20)	(6.32)	(6.69)	(10.41)	(9.56)
Natural gas ($/mcf)	(1.20)	(0.97)	(0.92)	(1.21)	(1.63)
Operating expenses (3)					
Oil ($/bbl) (2)	(8.88)	(12.12)	(9.89)	(6.64)	(6.45)
Natural gas ($/mcf)	(0.84)	(1.26)	(0.96)	(0.60)	(0.57)
Field netbacks					
Oil ($/bbl) (2)	12.16	6.81	10.70	11.00	20.21
Natural gas ($/mcf)	4.02	3.40	4.02	4.05	4.52

Notes:

(1) Selling prices are net of costs to transport the product to market.

(2) Includes a negligible amount of NGLs.

(3) Operating expenses include mineral and surface lease rentals, property taxes and expenses related to the operation and maintenance of wells, production facilities and gathering systems.

Production Volume by Field

The following table discloses for each significant field, and in total, Milagro's production volumes for the financial year ended December 31, 2003 for each product type.

Field	Light and Medium Crude Oil (bbl/d)	Natural Gas (mcf/d)	Natural Gas Liquids (bbl/d)	BOE (boe/d)	%
Battle Creek, Saskatchewan	286	1,875	–	599	91.9
Bittern Lake, Alberta	2	286	4	53	8.1
Total	288	2,161	4	652	100

INDUSTRY CONDITIONS

Canadian Government Regulation

The oil and natural gas industry is subject to extensive controls and regulations imposed by various levels of government. Outlined below are some of the more significant aspects of the relevant legislation and regulations. It is not expected that any of such controls and regulations will affect the operations of the Corporation in a manner materially different than they will affect other oil and gas companies of similar size.

Pricing and Marketing – Oil

Producers of oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Such price depends on oil quality, price of competing oils, distance to market and the value of refined products. Oil exporters are also entitled to enter into export contracts and export oil provided that, for contracts which do not exceed one year in the case of light crude oil and two years in the case of heavy crude oil, an export order must be obtained from the National Energy Board ("NEB") prior to the export. Any export pursuant to a contract of longer duration must be made pursuant to an NEB export license and Governor in Council approval.

Pricing and Marketing – Natural Gas

The price of natural gas sold in intra-provincial and inter-provincial trade is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the government of Canada. The price received by the Corporation depends, in part, on the prices of competing natural gas and other substitute fuels, access to downstream transportation, distance to markets, length of the contract term, weather conditions, the supply and demand balance and other contractual terms. Exporters are free to negotiate prices with purchasers, provided that the export contracts must continue to meet certain criteria prescribed by the NEB and the government of Canada. As in the case with oil, natural gas exports for a term of less than two years must be made pursuant to an NEB order and in the case of exports for a longer duration, pursuant to an NEB license and Governor in Council approval.

The government of Alberta also regulates the volume of natural gas which may be removed from the province for consumption elsewhere.

The North American Free Trade Agreement

On January 1, 1994, the North American Free Trade Agreement ("NAFTA") among the governments of Canada, the United States and Mexico became effective. NAFTA carries forward most of the material energy terms contained in the Canada-U.S. Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports to the U.S or Mexico will be allowed provided that the restrictions are otherwise justified under certain provisions of the General Agreement on Tariffs and Trade and then only if any export restrictions do not: (i) reduce the proportion of the energy resource exported relative to the total supply of energy resource (based upon the proportion prevailing in the most recent 36 months); (ii) impose an export price higher than the domestic price; or (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory boarder restrictions and export taxes. The agreement also contemplates clearer disciplines on regulators to avoid discriminatory actions and to minimize disruption of contractual arrangements.

Provincial Royalties and Incentives

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on well productivity, geographical location, field discovery data and the type or quality of the petroleum product produced.

From time to time the governments of Canada, Alberta and Saskatchewan have established incentive programs which have included royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas production and enhanced production projects.

Oil royalty rates vary from province to province. In Alberta, oil royalty rates vary between 10% and 35% for oil and 10% and 30% for new oil. New oil is applicable to oil pools discovered after March 31, 1974 and prior to October 1, 1992. The Alberta government introduced the Third Tier Royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 30, 1992.

Effective January 1, 1994, the calculations and payment of natural gas royalties became subject to a simplified process. The royalty reserved to the Crown, subject to various incentives, is between 15% to 30%, in the case of new gas, and between 15% and 35%, in the case of old gas, depending upon a prescribed or corporate average reference price. Natural gas produced from qualifying exploratory natural gas wells spudded or deepened after July 31, 1985 and before June 1, 1988 continues to be eligible for a royalty exemption for a period of 12 months, or such later time that the value of the exempted royalty quantity equals a prescribed maximum amount. Natural gas produced from qualifying intervals in eligible natural gas wells spudded or deepened to a depth below 2,500 metres is also subject to a royalty exemption, the amount of which depends on the depth of the well.

In Alberta, a producer of oil or natural gas is entitled to a credit against the royalties payable to the Crown by virtue of the ARTC program. The ARTC rate is based on the price-sensitive formula and varies between 75% for prices at or below the royalty tax credit reference price of $100 per cubic metre decreasing to 25% for prices above the royalty tax credit reference price of $210 per cubic metre. The ARTC rate will be applied to a maximum annual amount of $2,000,000 of Alberta Crown royalties payable for each producer or associated group of producers. Crown royalties on production from producing properties acquired from corporations claiming maximum entitlements to ARTC will generally not be eligible for ARTC. The rate is established quarterly based on the average par price, as determined by the Alberta Department of Energy, for the previous quarterly period. On December 22, 1997, the Alberta government announced that it would conduct a review of the ARTC program with the objective of setting out better targeted objectives for a smaller program and to deal with administrative difficulties. On August 30, 1999, the Alberta government announced that it would not be reducing the size of the program, but that it would introduce new rules to reduce the number of persons who qualify for the program. The new rules will preclude companies that pay less than $10,000 in royalties per year and non-corporate entities from qualifying from the program.

Effective October 1, 2002, the government of Saskatchewan revised its fiscal regime for the oil and gas industry by introducing a number of major changes affecting the Crown royalty and freehold production tax structures and the Corporation Capital Tax Surcharge rate applicable to production from new oil and gas exploration and development activity. The changes were implemented to stimulate increased exploration and development activity in the province.

The new fiscal regime in Saskatchewan provides new royalty and tax structures, a new system of volume incentives, and a reduced Corporation Capital Tax Surcharge rate. Other components are a new royalty/tax regime for gas produced from new oil wells and changes that benefit horizontal and deep oil wells. The "fourth tier" Crown royalty rate and freehold production tax structure is production and price sensitive and applies to: conventional oil wells (vertical and horizontal) and gas wells with a finished drilling date on or after October 1, 2002; incremental oil produced from new or expanded waterflood projects with a commencement date on or after October 1, 2001; and, natural gas produced from gas wells with a finished drilling date on or after October 1, 2002. The price sensitive parameters for the new "fourth tier" royalty structures provide: a base rate of 5% and marginal rate of 30% for both oil and gas; a base price of $100 per cubic metre for oil and $50 per thousand cubic metres for gas; and, a reference well production rate of 250 cubic metres of oil per month and 250 thousand cubic metres of gas per month.

The freehold production tax rates in Saskatchewan are now determined by subtracting a production tax factor of 12.5 percentage points (an increase in the previous 10 percentage point freehold production tax factor) from the corresponding Crown royalty rates. Further, the Corporation Capital Tax Surcharge rate has been decreased to 2.0% from 3.6% for: all oil and gas that is produced from oil wells or gas wells with a finished drilling date on or after October 1, 2002; and, incremental oil related to new or waterflood projects having a commencement date on or after October 1, 2002. In conjunction with the "fourth tier" royalty/tax structures, the government of Saskatchewan introduced a modified system of incentive volumes and maximum royalty/tax rates applicable to the initial production from oil wells and gas wells with a finished drilling date on or after October 1, 2002. The incentive volumes are applicable to various well types and are subject a maximum royalty rate of 2.5% and a freehold production tax rate of 0%. Re-entry and short section horizontal oil well royalty/tax categories have been eliminated. All horizontal oil wells with a finished drilling date on or after October 1, 2002 will receive the "fourth tier" royalty/tax rates and new incentive volumes. The definition of "deep oil well" has also been expanded.

The new Crown royalty and freehold production tax regime in Saskatchewan applies to associated natural gas (gas produced from oil wells) that is gathered for use or sale and is produced from: oil wells with a finished drilling date on or after October 1, 2002; and, oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of more than 3,500 cubic metres of gas for every cubic metre of oil. Effectively, a royalty/tax will be payable on associated natural gas produced from an oil well that exceeds approximately 65 thousand cubic metres in a month.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions and regulation on the storage and transportation of various substances produced or utilized in association with certain oil and gas industry operations and can affect the location and operation of wells and facilities and the extent to which exploration and development is permitted. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. As well, applicable environmental laws may impose remediation obligations with respect to property designated as a contaminated site upon certain responsible persons, which include persons responsible for the substance causing the contamination, persons who caused the release of the substance and any past or present owner, tenant or other person in possession of the site. Compliance with such legislation can require significant expenditures and a breach of such legislation may result in the suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, the imposition of fines and penalties or the issuance of clean-up orders. Applicable environmental laws in Alberta are consolidated in the Environmental Protection and Enhancement Act (the "EPEA"). Under the EPEA, environmental standards and compliance for releases, clean-up and reporting are stricter and more onerous than the previous legislation. Also, the range of enforcement actions available and the severity of penalties have been significantly increased. These changes will have an incremental effect on the cost of conducting operations in Alberta.

SELECTED FINANCIAL INFORMATION

Annual Financial Information

The following is a summary of selected financial information of the Corporation for the periods indicated, portions of which are derived from the audited financial statements of the Corporation for the years ended December 31, 2003, 2002 and 2001. Such financial statements, together with the notes thereto, are incorporated by reference herein.

	Year Ended December 31,		
(M$, except per share amounts)	2003	2002	2001
Oil and gas revenue	7,895	5,077	1,647
Cash flow from operations	3,095	2,455	566
Per share – basic	0.11	0.13	0.04
Per share – diluted	0.10	0.13	0.04
Net earnings	502	611	35
Per share – basic	0.02	0.03	–
Per share – diluted	0.02	0.03	–
Capital expenditures (net)	18,491	8,928	1,694
Total assets	31,897	15,138	6,384
Debt and working capital	2,879	2,604	908
Shareholders' equity	23,026	8,023	3,542

Note:

(1) Certain 2002 and 2001 amounts have been restated to reflect the retroactive application of adopting CICA handbook section 3110, "Asset Retirement Obligations" in 2003.

Quarterly Financial Information

The following is a summary of selected financial information of the Corporation for the periods indicated:

	2003					2002				
(M$, except per share amounts)	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Oil and gas revenue	7,895	1,832	1,802	1,725	2,536	5,077	2,112	1,228	1,039	698
Cash flow from operations	3,095	219	978	615	1,283	2,455	1,104	597	447	307
Per share – basic	0.11	–	0.03	0.03	0.05	0.13	0.06	0.03	0.02	0.02
Per share – diluted	0.10	–	0.03	0.03	0.05	0.13	0.06	0.03	0.02	0.02
Net earnings (loss)	502	(691)	562	201	430	611	350	117	88	56
Per share – basic	0.02	(0.02)	0.01	0.01	0.02	0.03	0.02	–	0.01	–
Per share – diluted	0.02	(0.02)	0.01	0.01	0.02	0.03	0.02	–	0.01	–

Dividends

Since incorporation Milagro has not paid any dividends on its common shares. Dividends on its common shares will be paid solely at the discretion of Milagro's board of directors after taking into account the financial condition of Milagro and the economic environment in which it is operating. No dividends are expected to be paid in the foreseeable future.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The Corporation's Management's Discussion and Analysis relating to the fiscal year ended December 31, 2003 contained in Milagro's annual report in the section entitled "Management's Discussion and Analysis" is incorporated herein by reference and forms an integral part of this Annual Information Form.

MARKET FOR SECURITIES

The common shares of the Corporation are listed for trading on the Toronto Stock Exchange under the symbol MIG. On April 30, 2004, Milagro's outstanding equity consisted of 41,498,802 common shares, 1,170,107 stock options at an average exercise price of $0.62 per share and 300,000 common share purchase warrants exercisable at $0.45 per share.

DIRECTORS AND OFFICERS

As of April 30, 2004, the name and municipalities of residence of the directors and officers, the number of voting securities of the Corporation beneficially owned, directly or indirectly, or over which each exercises control or direction, the offices held by each in the Corporation, the period served as director and the principal occupation of each during the last five years are as follows.

The information as to shares beneficially owned, directly or indirectly or over which control or direction is exercised, is based upon information furnished to the Corporation by the individuals indicated.

Name and Municipality of Residence	Number of Common Shares Beneficially Owned (1) (10)	Offices Held and Time as Director or Officer (2)	Principal Occupation During the Last Five Years
Jeffrey C. Rekunyk Calgary, Alberta	2,581,465	President and CEO Director since January 1999	President and CEO of the Corporation since January 1999. Prior to August 1999, Mr. Rekunyk was also the President and CEO of Milagro Oil Ltd. (a private oil and gas company), which was amalgamated with the Corporation in July 1999.
Michael J. Makinson (4) Calgary, Alberta	1,000,000 (8)	Vice President, Finance and CFO Director since December 2001	Vice President, Finance and CFO of the Corporation since November 2001. Prior to July 2001, Mr. Makinson was a Director, the Vice President, Finance and Corporate Secretary of BXL Energy Ltd. (a publicly traded oil and gas company).
Michael D. Charles Calgary, Alberta	495,500	Vice President, Land & Business Development	Vice President, Land & Business Development of the Corporation since May 2002. From March 1997 to May 2002, Mr. Charles was the Vice President, Land, Acquisitions and Divestitures of Vintage Petroleum Canada, Inc. and its predecessor, Genesis Exploration Ltd.
William C. Darling (3)(5)(6) Calgary, Alberta	839,633	Director since January 1999	President, Big Guns Perforating & Logging Inc. (an oilfield services company).
William C. Guinan (4)(5) Calgary, Alberta	353,693	Corporate Secretary Director since January 1999	Partner, Borden Ladner Gervais LLP (a law firm).
Robert J. Pritchard (3)(6) Calgary, Alberta	Nil	Director since December 2003	President and CEO of Taylor Gas Liquids Ltd., the general partner of Taylor NGL Limited Partnership.
Robert J. Robertshaw (3)(5)(6) Calgary, Alberta	2,346,189 (9)	Director since January 1999	President of Denim Pipeline Construction Ltd. (an oilfield services company).

Notes:

(1) The percentage of common shares beneficially owned, directly or indirectly, or over which control or direction is exercised by directors and senior officers as a group, amounted to approximately 18% at April 30, 2004.

(2) The term of office of each director expires at the next annual meeting of shareholders.

(3) Member of the Audit Committee which committee is required pursuant to the Business Corporations Act (Alberta).

(4) Member of the Corporate Governance Committee.

(5) Member of the Compensation Committee.

(6) Member of the Reserves Committee.

(7) The Corporation does not have an executive committee.

(8) Mr. Makinson also holds 300,000 common share purchase warrants, exercisable at a price of $0.45 per share until November 28, 2004.

(9) Mr. Robertshaw controls Kaibre Enterprises Ltd. which owns 1,619,128 of these shares.

(10) In addition to the common shares of Milagro beneficially owned, the directors and officers of the Corporation hold an aggregate 888,442 stock options as at April 30, 2004.

CONFLICTS

There are potential conflicts of interest to which the directors and officers of Milagro will be subject in connection with the operations of Milagro. In particular, certain of the directors and officers of Milagro are involved in managerial or director positions with other oil and gas companies whose operations may, from time to time, be in direct competition with those of Milagro or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of Milagro. See "Directors and Officers". Conflicts, if any, will be subject to the procedures and remedies available under the ABCA. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the ABCA.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remunerations, principal holders of the Corporation's securities, options to purchase securities and interests of insiders in material transactions is contained in the Corporation's Management Information Circular relating to the Annual Meeting of Shareholders to be held on June 10, 2004. Additional financial information is contained in the Corporation's comparative financial statements for the years ended December 31, 2003 and 2002.

Additional copies of this Annual Information Form, the materials listed in the preceding paragraph, any interim financial statements which have been issued by the Corporation and any other document incorporated herein by reference will be available upon request by contacting the Vice President, Finance and Chief Financial Officer of the Corporation at its offices at 1000, 633 – 6th Avenue SW, Calgary, Alberta, T2P 2Y5, Phone: (403) 693-4000 or Fax: (403) 693-4001.

APPENDIX A: Form 51-101F2

Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor

To the board of directors of Milagro Energy Inc. (the "Company"):

1. We have prepared an evaluation of the Company's reserves data as at December 31, 2003. The reserves data consist of the following:
   - (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2003 using forecast prices and costs (based on January 1, 2004 pricing assumptions); and
     - (ii) the related estimated future net revenue; and
   - (b) (i) proved oil and gas reserves estimated as at December 31, 2003 using constant prices and costs; and
     - (ii) the related estimated future net revenue.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2003, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
Gilbert Laustsen Jung Associates Ltd.	March 4, 2004	Canada	$0	$23.4MM	$0	$23.4MM

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.

6. We have no responsibility to update this evaluation for events and circumstances occurring after the preparation dates.

7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Gilbert Laustsen Jung Associates Ltd.
Calgary, Alberta, Canada

Wayne Chow

Wayne W. Chow, P.Eng.
Vice-President

April 5, 2004

APPENDIX B: Form 51-101F2

Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor

To the board of directors of Milagro Energy Inc. (the "Company"):

1. We have prepared an evaluation of the Company's reserves data as at December 31, 2003. The reserves data consist of the following:
   (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2003 using forecast prices and costs (based on April 1, 2004 pricing assumptions); and
   (ii) the related estimated future net revenue; and
   (b) (i) proved oil and gas reserves estimated as at December 31, 2003 using constant prices and costs; and
   (ii) the related estimated future net revenue.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2003, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
Gilbert Laustsen Jung Associates Ltd.	March 4, 2004	Canada	$0	$26.8MM	$0	$26.8MM

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.

6. We have no responsibility to update this evaluation for events and circumstances occurring after the preparation dates.

7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Gilbert Laustsen Jung Associates Ltd.
Calgary, Alberta, Canada

Wayne W. Chow, P.Eng.
Vice-President

March 18, 2004

APPENDIX C: Form 51-101F3

Report of Management and Directors on Oil and Gas Disclosure

This is the form referred to in item 3 of section 2.1 of National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). This form does not apply in British Columbia.

1. Terms to which a meaning is ascribed in NI 51-101 have the same meaning in this form.
2. The report referred to in item 3 of section 2.1 of NI 51-101 shall in all material respects be as follows:

Report of Management and Directors on Reserves Data and Other Information

Management of Milagro Energy Inc. (the "Corporation") are responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2003 using forecast prices and costs (using January 1, 2004 and April 1, 2004 pricing assumptions); and
(ii) the related estimated future net revenue; and

(b) (i) proved oil and gas reserves estimated as at December 31, 2003 using constant prices and costs; and
(ii) the related estimated future net revenue.

An independent qualified reserves evaluator has evaluated the Corporation's reserves data. The reports of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of the Corporation has:

(a) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluator;
(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and
(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves Committee approved:

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;
(b) the filing of the reports of the independent qualified reserves evaluator on the reserves data; and
(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Jeffrey C. Rekunyk
President and Chief Executive Officer

Michael J. Makinson
Vice President, Finance and Chief Financial Officer

Robert J. Pritchard
Director

William C. Darling
Director

April 30, 2004

(1) For the convenience of readers, Appendix 1 to Companion Policy 5I-I0ICP sets out the meanings of terms that are printed in italics in sections 1 and 2 of this Form or in NI 51-101, Form 51-101F1, Form 5I-101F2 or the Companion Policy.

APPENDIX D: Definitions Used for Reserve Categories

Reserves estimates have been prepared by Gilbert Laustsen Jung Associates Ltd. (GLJ) in accordance with standards contained in the Canadian Oil and Gas Evaluation (COGE) Handbook. The following reserves definitions are set out by the Canadian Securities Administrators in National Instrument 51-101 (NI51-101; in Part 2 of Appendix 1 to Companion Policy 51-101CP) with reference to the COGE Handbook.

Reserve Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from know accumulations, from a given date forward, based on:

- analysis of drilling, geological, geophysical, and engineering data;
- the use of established technology;
- specified economic conditions [(1)], which are generally accepted as being reasonable, and shall be disclosed.

Reserves are classified according to the degree of certainty associated with the estimates.

Proved Reserves

Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

Probable Reserves

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Possible Reserves

Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

Other criteria that must also be met for the categorization of reserves are provided in [Section 5.5 of the COGE Handbook].

Development and Production Status

Each of the reserves categories (proved, probable, and possible) may be divided into developed and undeveloped categories.

Developed Reserves

Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

Developed Producing Reserves

Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be know with reasonable certainty.

Developed Non-Producing Reserves

Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

Undeveloped Reserves

Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

Notes:

(1) For the purposes of NI 51-101, the key economic assumptions will be the prices and costs used in the estimate, namely:
(a) constant prices and costs as at the last day of a reporting issuer's financial year; or
(b) forecast prices and costs.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserves entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves estimates are presented). Reported Reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves;
- at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in Section 5.5.3 of the COGE Handbook.

Incorporation of these guidelines means that total corporate proved reserves reflect a conservative estimated and proved plus probable reserves reflect a current "best estimate" of the oil and gas quantities which will be recovered.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This management's discussion and analysis ("MD&A") should be read in conjunction with Milagro's audited financial statements for the years ended December 31, 2003 and 2002.

This MD&A contains forward-looking statements. Forward-looking statements are based on current expectations that involve a number of risks and uncertainties which could cause actual events or results to differ materially from those reflected in the MD&A. Forward-looking statements are based on the estimates and opinions of Milagro's management at the time the statements were made.

Per barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil ("6:1"). The 6:1 conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Boe disclosure may be misleading, particularly if used in isolation.

The MD&A contains the term cash flow from operations, which should not be considered an alternative to, or more meaningful than, cash flow from operating activities as determined in accordance with Canadian generally accepted accounting principles as an indicator of the Company's performance. Milagro's calculation of cash flow from operations may not be comparable to that reported by other companies. The reconciliation between net earnings and cash flow from operations can be found in the statements of cash flows in the unaudited interim financial statements and the audited financial statements. Cash flow from operations per share is calculated using the same weighted average number of shares outstanding used in the calculation of earnings per share.

SELECTED ANNUAL INFORMATION

	2003	2002	2001
Financial (1)			
($000s except per share data)			
Oil and natural gas revenue	**7,895**	5,077	1,647
Cash flow from operations	**3,095**	2,455	566
Per share – diluted	**0.10**	0.13	0.04
Net earnings	**502**	611	35
Per share – diluted	**0.02**	0.03	–
Capital expenditures (net)	**18,491**	8,928	1,694
Debt and working capital	**2,879**	2,604	908
Shareholders' equity	**23,026**	8,023	3,542
Total assets	**31,897**	15,138	6,384
Operating			
Average daily production			
Oil (bbls per day)	**292**	235	205
Natural gas (mcf per day)	**2,161**	1,767	122
Equivalent barrels (boe per day)	**652**	530	225
Wells drilled			
Gross	**18**	24	6
Net	**18.0**	20.3	4.8

(1) Certain 2002 and 2001 amounts have been restated to reflect the retroactive application of adopting CICA handbook Section 3110, Asset Retirement Obligations in 2003.

2003 OVERVIEW

Milagro's $18.6 million capital expenditure program was allocated to the following areas: southwest Saskatchewan – $11.5 million; central Alberta – $5.7 million; west central Alberta – $1.2 million; and corporate $0.2 million. Notable expenditures included the drilling of 18 wells, the expansion of a natural gas compression and dehydration facility in southwest Saskatchewan, commencement of construction of a larger oil battery and water disposal system in southwest Saskatchewan, and the acquisition of 61 sections of new exploratory mineral rights. Capital expenditures were funded 82 percent through the issuance of new equity, 17 percent by cash flow from operations and one percent from changes working capital.

During 2003 Milagro issued a total of $16.3 million of new equity, primarily from two private placements. In August, 13.5 million common shares were issued at $0.80 per share for proceeds of $10.8 million. In October, 2.0 million common shares were issued at $1.04 per share and 2.3 million flow-through common shares were issued at $1.30 per share, for total proceeds of $5.1 million.

Average daily production in 2003 was 652 boe per day, 55 percent natural gas and 45 percent oil and NGLs. Production in 2003 was 23 percent higher than 2002, but lower than forecast. In southwest Saskatchewan, natural gas production from wells drilled in late 2002 declined quicker than anticipated and growth in oil production was held back by delays in the construction of a new battery. In central Alberta, follow-up drilling to Milagro's early 2003 natural gas discovery met with mixed results.

Milagro completed 2003 in strong financial condition. December 31, 2003 net debt of $2.9 million is less than one times trailing cash flow.

Milagro's 2003 financial statements include the effects of a new industry disclosure standard and three new accounting policies. The new standard for disclosure of oil and gas activities includes more conservative reserve definitions, which affects the provision for depletion and depreciation. The new full cost accounting policy modifies the ceiling test calculation and the provision for depletion and depreciation. The new accounting policy regarding the retirement of long-lived assets requires the estimated fair value of asset retirement obligations be added to the cost of oil and natural gas properties and recorded as a long-term liability. The new accounting policy on stock-based compensation requires financial statement recognition of an expense when stock options are issued.

DETAILED FINANCIAL ANALYSIS

Production

	Three Months Ended Dec. 31,			Year Ended Dec. 31,		
	2003	2002	% Change	**2003**	2002	% Change
Oil and NGLs (bbls/day)	**339**	320	6	**292**	235	24
Natural gas (mcf/day)	**2,015**	2,630	(23)	**2,161**	1,767	22
Boe (boe/day)	**675**	758	(11)	**652**	530	23

Production for the three months ended December 31, 2003 averaged 675 boe per day, 11 percent lower than the same period in 2002. Oil and NGLs production increased 6 percent to 339 barrels per day while natural gas production declined 23 percent to 2,015 mcf per day. Fourth quarter 2003 oil production is higher due to new oil wells in southwest Saskatchewan. The comparative decline in fourth quarter natural gas production is primarily due to flush production in 2002 from a number of wells drilled during the second half of that year. During the fourth quarter of 2003, Milagro produced 324 barrels of oil per day in southwest Saskatchewan and 15 barrels of oil and NGLs per day in central Alberta. Fourth quarter natural gas production was 1,532 mcf per day in southwest Saskatchewan and 483 mcf per day in central Alberta. All of Milagro's 2002 production came from southwest Saskatchewan.

Production for the year ended December 31, 2003 averaged 652 boe per day, a 23 percent increase compared to last year. Oil production increased 24 percent to 292 barrels per day and natural gas production increased 22 percent to 2,161 mcf per day. Higher oil production is primarily the result of drilling and production optimization in southwest Saskatchewan. The year-over-year increase in natural gas production is a result of new wells in southwest Saskatchewan that were placed on production during the second half of 2002 and new production in central Alberta that came on stream during the summer of 2003.

Selling Prices

Milagro Field Prices

	Three Months Ended Dec. 31,			Year Ended Dec. 31,		
	2003	2002	% Change	**2003**	2002	% Change
Oil and NGLs ($ per bbl)	**25.25**	28.88	(13)	**29.24**	28.60	2
Natural gas ($ per mcf)	**5.63**	5.22	8	**6.06**	4.06	49
Boe ($ per boe)	**29.49**	30.28	(3)	**33.19**	26.25	26

Benchmark Prices

	Three Months Ended Dec. 31,			Year Ended Dec. 31,		
	2003	2002	% Change	**2003**	2002	% Change
Oil – WTI Cushing (US$/bbl)	**31.18**	28.14	11	**31.04**	26.08	19
Oil – Edmonton Light (Cdn$/bbl)	**39.56**	42.81	(8)	**43.14**	39.90	8
Gas – AECO–C						
daily spot (Cdn$/mcf)	**5.59**	5.26	6	**6.67**	4.08	63
US$/Cdn$ exchange rate	**0.763**	0.637	20	**0.714**	0.637	12

Fourth quarter 2003 oil and NGL selling prices averaged $25.25 per barrel, down 13 percent from prices received during the last quarter of 2002. Realized natural gas prices were $5.63 per mcf in 2003, up eight percent from prices received during the same period last year. Throughout 2003 and 2002, Milagro sold all of its oil production at spot prices and sold a portion of its natural gas production through forward sales arrangements. For the fourth quarter of 2003, the forward sales arrangements resulted in an increase in revenue of $27,200 ($0.15 per mcf) as compared to a decrease in revenue of $64,700 ($0.27 per mcf) during the same period in 2002.

Milagro's 2003 realized selling prices were $29.24 per barrel of oil and NGL and $6.06 per mcf of natural gas. For the year ended December 31, 2003, forward sales of natural gas resulted in a decrease in revenue of $256,400 or $0.33 per mcf. Forward sales had minimal effect on annual revenue in 2002.

Revenue

($000s)	Three Months Ended Dec. 31, 2003	2002	% Change	Year Ended Dec. 31, 2003	2002	% Change
Oil and NGLs	**789**	850	(7)	**3,113**	2,455	27
Natural gas	**1,043**	1,262	(17)	**4,782**	2,622	82
Total	**1,832**	2,112	(13)	**7,895**	5,077	56

Comparing the last quarter of 2003 to the same period in 2002, revenue declined 13 percent to $1,832,000. Oil revenue declined by seven percent as lower prices overcame higher production volumes and natural gas revenue declined 17 percent as lower production volumes overcame higher prices.

On an annual comparison, higher production volumes and higher prices pushed 2003 revenue up 56 percent to $7,895,000.

Royalties

	Three Months Ended Dec. 31, 2003	2002	% Change	Year Ended Dec. 31, 2003	2002	% Change
($000s)						
Crown	**231**	475	(51)	**1,438**	1,068	35
Overriding and Freehold	**146**	62	135	**381**	181	110
Total	**377**	537	(30)	**1,819**	1,249	46
Royalty rate (% of revenue)	**21%**	25%		**23%**	25%	
$ Per boe	**6.06**	7.70	(21)	**7.65**	6.46	18

Royalties in the three months ended December 31, 2003 were $377,000, 30 percent less than the $537,000 recorded in the last quarter of 2002. On a quarterly comparison, fourth quarter 2003 royalties declined due to lower revenue and a decrease in the effective rate to 21 percent of revenue in 2003 from 25 percent in 2002. On an annual basis, 2003 royalties were $1,819,000, up 46 percent compared to 2002. The year-over-year increase is primarily due to higher revenue, partially offset by a reduction in the effective rate to 23 percent of revenue from 25 percent. Milagro's effective royalty rate has fallen as a result of relatively lower Crown royalties on natural gas production in southwest Saskatchewan. Flush production during the second half of 2002 resulted in higher effective Crown royalty rates.

Production Expenses

	Three Months Ended Dec. 31,			Year Ended Dec. 31,		
	2003	2002	% Change	**2003**	2002	% Change
Oil and NGLs ($ per bbl)	**12.12**	5.14	136	**8.88**	5.45	63
Natural gas ($ per mcf)	**1.26**	0.67	88	**0.84**	0.60	40
Boe ($ per boe)	**9.87**	4.48	120	**6.76**	4.42	53

Production expenses increased 96 percent to $613,000 in the fourth quarter of 2003 from $313,000 in the fourth quarter of 2002. On a unit basis, oil and NGL expenses increased 136 percent to $12.12 per barrel and natural gas expenses increased 90 percent to $1.26 per mcf. Fourth quarter 2003 oil and NGL expenses are exceptionally high and temporary for two reasons. First, as a consequence of the delay in completing the new oil battery in southwest Saskatchewan, new oil wells were placed on stream using a combination of the old batteries, parts of the new battery and temporary equipment. Second, Milagro encountered high operating costs bringing on new oil production in central Alberta. Natural gas expenses are higher as a result of production in central Alberta introduced in mid 2003. Central Alberta operating costs are higher because Milagro pays third parties to transport and process its natural gas.

On a year-over-year basis, production expenses increased 88 percent to $1,609,000 in 2003 from $855,000 in 2002. Higher costs were the result of the 23 percent increase in average daily production volumes and a 53 percent increase in overall unit costs. In addition to higher costs in the fourth quarter of 2003 as described above, 2003 annual costs were impacted by higher maintenance and repair costs for wells in southwest Saskatchewan.

Field Netbacks

	Three Months Ended Dec. 31,			Year Ended Dec. 31,		
	2003	2002	% Change	**2003**	2002	% Change
Oil and NGLs ($ per bbl)	**6.81**	15.89	(57)	**12.16**	16.63	(27)
Natural gas ($ per mcf)	**3.39**	3.29	3	**4.02**	2.39	68
Boe ($ per boe)	**13.56**	18.10	(25)	**18.78**	15.37	22

Fourth quarter 2003 field netbacks were $13.56 per boe, broken down as to $6.81 per barrel of oil and NGL and $3.39 per mcf of natural gas. Compared to the fourth quarter of 2002, oil and NGL netbacks declined 57 percent largely due to higher production expenses and natural gas netbacks increased 3 percent, as higher selling prices and lower royalties offset higher production expenses.

Field netbacks for the year ended December 31, 2003 were $18.78 per boe, broken down as to $12.16 per barrel of oil and NGL and $4.02 per mcf of natural gas. On a year-over-year basis, oil and NGL netbacks declined 27 percent due to increases in royalties and production expenses and natural gas netbacks increased 68 percent primarily due to higher selling prices.

General and Administrative Expenses

	Three Months Ended Dec. 31,			Year Ended Dec. 31,		
($000s)	**2003**	2002	% Change	**2003**	2002	% Change
Total	**572**	243	135	**1,479**	734	101
Overhead recoveries	**(177)**	(99)	79	**(395)**	(242)	63
Capitalized	**(31)**	(15)	107	**(122)**	(71)	72
Expensed	**364**	129	182	**962**	421	129
Expensed per boe ($ per boe)	**5.85**	1.85	216	**4.04**	2.18	85

Compared to the same period last year, fourth quarter 2003 total general and administrative ("G&A") costs increased 135 percent to $572,000. Higher personnel costs, amounts incurred to list Milagro's shares on the Toronto Stock Exchange and higher costs regarding independent reserves evaluations contributed to the increase. On a quarterly comparison, overhead recoveries and amounts capitalized to oil and gas properties increased as a result of higher activity levels.

For the year ended December 31, 2003, total G&A costs were $1,479,000, up 101 percent from the previous year. The largest contributors to the increase were personnel and public company related costs. The 63 percent increase in overhead recoveries is the result of a larger capital expenditure program and a higher producing well count. All of Milagro's capital projects, production facilities and producing wells are burdened with an industry-accepted overhead charge that reduces corporate G&A costs expensed. During 2003, Milagro operated all of its capital projects and producing wells. During 2003, Milagro capitalized $122,000 of exploration related salaries to oil and gas properties.

Financing Charges

Financing charges were minimal during the fourth quarter of 2003 as a result of low average debt levels and interest earned. As a result of the private placements completed in August and October 2003, Milagro carried a cash balance through most of the quarter.

Financing charges for the year ended December 31, 2003 were $124,000, up 29 percent from amounts incurred in 2002. Financing charges in 2003 were incurred primarily in the first half of the year, whereas 2002 financing charges were incurred more evenly throughout the year. On a unit basis, 2003 financing charges were $0.52 per boe, up marginally from $0.49 per boe in 2002.

Depletion, Depreciation and Accretion

	Three Months Ended Dec. 31,			Year Ended Dec. 31,		
($000s)	**2003**	2002	% Change	**2003**	2002	% Change
Depletion and depreciation of oil and gas properties	**973**	531	83	**2,505**	1,326	89
Accretion of asset retirement obligations	**14**	20	(30)	**53**	50	6
Depreciation of office equipment	**5**	5	–	**23**	19	21
Total	**992**	556	78	**2,581**	1,395	85
($/boe)						
Depletion and depreciation of oil and gas properties	**15.66**	7.61	106	**10.53**	6.86	53
Accretion of asset retirement obligations	**0.23**	0.29	(21)	**0.22**	0.26	(15)
Depreciation of office equipment	**0.08**	0.08	–	**0.10**	0.09	11
Total	**15.97**	7.98	100	**10.85**	7.21	50

The provision for depletion, depreciation and accretion ("DD&A expense") is comprised of three components: depletion and depreciation of oil and gas properties; accretion of asset retirement obligations; and depreciation of office equipment. Depletion and depreciation of oil and gas properties is computed using the unit-of-production method based on proved reserves estimated at the end of the period. Accretion of asset retirement obligations is computed by applying a credit-adjusted risk-free interest rate to the beginning of the period liability balance.

For the year ended December 31, 2003, DD&A expense was $2,581,000, an 85 percent increase over the amount recorded in 2002. The overall increase in DD&A expense is due to higher unit rates for the depletion and depreciation of oil and gas properties. Higher depletion and depreciation unit rates were caused by two factors. First, the ratio of capital expenditures to proved reserves booked in 2003 was high. Second, Milagro's 2003 year-end estimate of proved reserves, as assigned by independent reserves evaluators, included a negative adjustment to the year's opening balances. The combination of these two events resulted in a fourth quarter 2003 depletion and depreciation unit rate of $15.66 per boe, more than double the unit rate of the last quarter of 2002.

Stock-based Compensation

The 2003 financial statements include stock-based compensation expense for all stock options granted after December 31, 2002 and for stock options granted prior to January 1, 2003 to consultants. The 2002 financial statements include stock-based compensation expense related to stock options granted to consultants in 2002. Stock-based compensation is charged to contributed surplus and does not affect cash flow from operations.

In 2003, Milagro recorded stock-based compensation expense of $18,000, up from $7,000 in 2002. Most of the 2003 increase occurred in the last quarter, when the amount to record stock options granted during 2003 was booked.

Taxes

Cash taxes for 2003 are comprised of the Federal Large Corporations Tax ($49,000) and the Saskatchewan Capital Tax ($237,000). Capital taxes are calculated with reference to a corporation's "taxable capital" as defined by various jurisdictions. Capital taxes are payable when a corporation's taxable capital exceeds a minimum threshold. During 2003, Milagro's taxable capital exceeded the Federal and Saskatchewan thresholds. The Federal capital tax was recorded throughout the year whereas the Saskatchewan capital tax was recorded in the fourth quarter. Milagro did not incur current income taxes in 2003 and did not pay current income taxes or capital taxes in 2002.

For the year ended December 31, 2003, Milagro recorded a future income tax recovery of $6,000, compared to future income tax expense of $443,000 in 2002. The amount recorded for 2003 includes a $454,000 benefit relating to the expected reduction in the Federal and provincial income tax rates. These changes were substantively enacted during the summer of 2003.

At the end of 2003, Milagro had estimated income tax deductions of approximately $20.6 million available to reduce future taxable income. The table below summarizes these deductions by category. The final balances may be revised as a result of a change in filing position or an audit and reassessment by Canada Customs and Revenue Agency. Any revision is not expected to be material to Milagro's overall income tax horizon.

	Available Balance	Deduction Rate %
Canadian exploration expense	$ 1,600,000	100
Canadian development expense	3,800,000	30
Canadian oil and gas property expense	2,700,000	10
Undepreciated capital cost	11,400,000	20-30
Other	1,100,000	20
Total	$ 20,600,000	

Cash Flow From Operations

Cash flow from operations was $219,000 (nil per share) in the fourth quarter of 2003 as compared to $1,104,000 ($0.06 per diluted share) during the same period last year. The drop in cash flow is the result of lower revenue, higher production expenses, higher general and administrative expenses and capital taxes.

For the year ended December 31, 2003, cash flow from operations was $3,095,000 ($0.10 per diluted share) as compared to $2,455,000 ($0.13 per diluted share) in 2002. Higher revenues in 2003 exceeded the increases in all cash expenses.

Corporate Cash Netbacks

	Three Months Ended Dec. 31,			Year Ended Dec. 31,		
($ per boe)	**2003**	2002	% Change	**2003**	2002	% Change
Field netbacks	**13.56**	18.10	(25)	**18.78**	15.37	22
General and admin. expenses	**(5.85)**	(1.85)	216	**(4.04)**	(2.18)	85
Financing charges	**(0.01)**	(0.42)	(98)	**(0.52)**	(0.49)	6
Current taxes	**(4.18)**	–	N/A	**(1.21)**	–	N/A
Cash flow from operations	**3.52**	15.83	(78)	**13.01**	12.70	2

Net Earnings (Loss)

Milagro recorded a loss from operations of $691,000 in the fourth quarter of 2003 as compared to net earnings of $350,000 for the same period in 2002. The 2003 loss from operations was largely the result of a general increase in expenses without a commensurate increase in revenue.

For the year ended December 31, 2003, Milagro recorded net earnings of $502,000 ($0.02 per share – diluted), down from $611,000 ($0.03 per share – diluted) in 2002. A 56 percent growth in year-over-year revenue was overshadowed by larger increases in most expenses.

Capital Expenditures

	Three Months Ended Dec. 31,			Year Ended Dec. 31,		
($000s)	**2003**	2002	% Change	**2003**	2002	% Change
Land acquisition and retention	**407**	945	(57)	**1,526**	985	55
Geological and geophysical	**77**	9	756	**486**	47	934
Drilling and completions	**2,289**	2,077	10	**7,198**	4,219	71
Production equipment and facilities	**5,292**	729	626	**9,263**	2,981	211
Property acquisitions	**–**	–	–	**–**	502	–
Capitalized overhead	**31**	15	107	**122**	71	72
Office	**–**	47	–	**16**	123	(87)
Total expenditures	**8,096**	3,822	112	**18,611**	8,928	108
Dispositions	**(120)**	–	–	**(120)**	–	–
Net expenditures	**7,976**	3,822	109	**18,491**	8,928	107

Milagro's 2003 capital expenditures were $18,491,000, more than double the $8,928,000 invested in 2002. In southwest Saskatchewan, Milagro acquired 12 sections of exploratory mineral rights, drilled 11 wells, equipped and tied in six oil wells and two gas wells, expanded compression and dehydration facilities and commenced construction of a large oil battery and water handling facility. In central Alberta, Milagro completed two 3-D seismic surveys,

acquired five sections of exploratory mineral rights, drilled 6 wells, re-completed 1 well and equipped and tied in three wells. In west central Alberta, 44 sections of mineral rights were acquired and 1 well commenced drilling prior to year-end. Forty-four percent of 2003 capital expenditures were incurred in the fourth quarter, primarily as a result of high activity levels in southwest Saskatchewan. Capital investment in 2003 was allocated as follows: southwest Saskatchewan – $11,504,000; central Alberta – $5,719,000; west central Alberta – $1,204,000; and corporate – $184,000. During the last quarter of 2003, Milagro sold exploratory mineral rights in southwest Saskatchewan for $120,000. In 2003, Milagro reinvested 6.0 times (2002 – 3.6 times) its cash flow from operations.

LIQUIDITY AND CAPITAL RESOURCES

	Three Months Ended Dec. 31,			Year Ended Dec. 31,		
($000s)	**2003**	2002	% Change	**2003**	2002	% Change
Cash flow from operations	**219**	1,104	(80)	**3,095**	2,455	26
Net proceeds from shares issued	**4,820**	2,354	105	**15,121**	4,777	217
Increase (decrease) in bank debt	**1,556**	542	187	**(405)**	1,166	(134)
Change in working capital	**1,381**	(177)	880	**680**	530	28
Total funding	**7,976**	3,823	109	**18,491**	8,928	107

At December 31, 2003, Milagro's net debt (working capital deficiency including bank debt) was $2,879,000, down from $2,604,000 at December 31, 2002. Milagro has a $7.0 million demand revolving production loan with its principal lender, the terms of which are reviewed annually.

Milagro's 2003 capital expenditure program was funded 82 percent through the issuance of new equity, 17 percent by cash flow from operations and one percent from changes in working capital (including bank debt). During 2003, Milagro issued 18,806,773 common shares for gross proceeds of $16,288,554, as follows:

Private placement of 13,500,000 common shares at $0.80 per share	$ 10,800,000
Private placement of 2,300,000 flow-through common shares at $1.30 per share	2,990,000
Private placement of 2,000,000 common shares at $1.04 per share	2,080,000
Exercise of options to acquire 706,773 common shares	283,554
Exercise of 300,000 common share purchase warrants at $0.45 per share	135,000

Milagro had 41,465,468 common shares outstanding at December 31, 2003 – 18 percent held by officers and directors.

During 2003, 125,000 stock options were granted at an average exercise price of $1.00 per share, 706,377 stock options were exercised at an average price of $0.40 per share and 100,000 stock options were cancelled. At December 31, 2003, Milagro had 1,203,441 stock options outstanding with an average exercise price of $0.62 per share.

During 2003, 300,000 common shares purchase warrants were exercised at $0.45 per share. At December 31, 2003 there were 300,000 common share purchase warrants outstanding, exercisable at $0.45 per share until November 28, 2004.

CONTRACTUAL OBLIGATIONS

Milagro has identified the following contractual obligations:

Flow-through share commitments – In October 2003, Milagro issued 2,300,000 flow-through common shares at $1.30 per share for proceeds of $2,990,000. Income tax deductions of $2,990,000 were renounced to subscribers effective December 31, 2003. Qualifying expenditures of approximately $1,400,000 were incurred before December 31, 2003, leaving approximately $1,590,000 to be incurred before December 31, 2004. Of the total to be incurred in 2004, $590,000 must qualify as Canadian Exploration Expense.

Office space – Milagro has entered into a lease for its office premises through to November 30, 2004. The estimated amount to be paid under this lease during 2004 is $83,000.

Asset Retirement Obligations – Milagro is the owner of oil and natural gas wells and related surface equipment and facilities. These assets will have to be abandoned and the surface returned to its natural state. At December 31, 2003, Milagro estimated its future asset retirement obligation to be $1,863,000, which is exclusive of salvage values. Milagro estimates that the salvage value of its field equipment would offset a significant portion of its estimated future asset retirement obligation. Milagro does not expect to incur significant asset retirement cost obligations within the next five years.

NEW ACCOUNTING STANDARDS AND REGULATORY CHANGES

There have been a number of changes in the financial reporting and securities regulatory environment in 2003. A summary of the changes and their affect on Milagro is summarized below.

New Accounting Standards

Full Cost Accounting – In September 2003, the CICA issued Accounting Guideline16, *Oil and Gas Accounting – Full Cost* to replace Accounting Guideline 5, Full *Cost Accounting in the Oil and Gas Industry*. The new guideline, which is effective for fiscal years beginning on or after January 1, 2004, modifies the ceiling test calculation and outlines additional disclosure requirements. Milagro adopted the new guideline in 2003 in accordance with the transitional provisions that encouraged early implementation. The ceiling test (impairment test) is now a two-step calculation. The first step identifies impairment by comparing the carrying amount of oil and gas properties to the sum of the undiscounted cash flows expected to result from proved reserves. If the carrying amount exceeds the undiscounted cash flows expected from proved reserves, then the magnitude of the impairment is measured as the excess of the

carrying amount over and above the estimated net present value of future cash flows expected from proved plus probable reserves. All future cash flows are calculated without deduction for financing charges, general and administrative expenses and taxes. There was no impact on the Milagro's reported financial results as a result of adopting the new accounting guideline.

Asset Retirement Obligations – In March 2003, new CICA Handbook Section 3110, *Asset Retirement Obligations* ("ARO") was issued. The new standard is effective for fiscal years beginning on or after January 1, 2004 but early adoption is encouraged. Milagro's adoption of the new standard in 2003 was applied retroactively with restatement of prior periods. The ARO standard requires recognition in the financial statements of the liability associated with retiring tangible long-lived assets such as oil and gas wells and related equipment. These obligations are initially measured at fair value when incurred, which is the discounted future value of the liability. This fair value is added to the carrying amount of the related asset and amortized to expense over its useful life. The liability accretes until the retirement obligation is settled. As a result of adopting the new standard, December 31, 2003 liabilities increased by $688,000, property and equipment increased by $778,000 and net earnings for the year then ended decreased by $14,000. Applying the new standard retroactively resulted in a decrease in 2002 net earnings of $10,000, an increase in liabilities of $535,400 and an increase in property and equipment of $524,000. Opening 2003 retained earnings decreased by $11,400 to account for the cumulative effect of the retroactive restatement for all prior years.

Stock-based Compensation – In September 2003, the CICA issued an amendment to Handbook Section 3870, *Stock-based Compensation and Other Stock-based Payments*. The amended section is effective for fiscal years commencing on or after January 1, 2004; however, early adoption is recommended. Milagro prospectively adopted the amendment in 2003. The amendment requires that stock options granted to employees, officers, directors and consultants be recognized as expenses in the financial statements using the fair value method. Under this method of accounting, stock-based compensation expense is recognized when an option is granted, based on the fair value of the option on the date of grant. Prior to the adoption of the new standard, the Company accounted for the grant of stock options to employees and directors using the intrinsic value method. Under this method, no compensation expense is recorded for stock options granted at prevailing market prices. Under the transitional provisions of the standard, Milagro accounts for all stock options granted after December 31, 2002 using the fair value method while stock options granted to employees and directors during 2002 are accounted for using the intrinsic value method. The Company discloses pro forma stock-based compensation expense and pro forma net earnings that would have resulted had the fair value method been used to account for stock options granted to employees and directors during

2002. For the year ended December 31, 2003, the adoption of the amended accounting standard resulted in a decrease in net earnings and an increase in contributed surplus of $7,000.

Hedging Relationships – In December 2001, the CICA issued Accounting Guideline 13, *Hedging Relationships* that establishes standards for the documentation and the measurement of the effectiveness of hedging relationships for the purposes of applying hedge accounting. The guideline is effective for fiscal years beginning on or after July 1, 2003. At December 31, 2003, Milagro did not have any hedges in place. Milagro may enter into hedging transactions to manage its exposure to risk, and this guideline may affect financial statements in the future.

Regulatory Changes

Oil and Gas Reserves - Effective September 30, 2003, National Instrument 51-101, *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") replaced National Policy 2-B ("NP-2B"). NI 51-101 requires a higher degree of confidence in the assignment of oil and gas reserves and includes revisions on how reserves information is disclosed. Under NI 51-101, proved reserves are defined to have a 90 percent probability (up from 80 percent under NP-2B) that the actual reserves recovered will equal or exceed the assigned estimates, while probable reserves are defined to have a 50 percent probability (up from 40 percent under NP-2B) that the actual reserves recovered will equal or exceed the assigned estimates. The revised definitions may result in one-time negative reserve adjustments, which can impact accounting calculations such as oil and gas depletion and depreciation and the ceiling test. Milagro's December 31, 2003 reserves were evaluated pursuant to NI 51-101 and likely resulted in higher depletion and depreciation charges for the year.

Continuous Disclosure Obligations – Effective March 31, 2004, all reporting issuers in Canada will be subject to National Instrument 51-102, C*ontinuous Disclosure Obligations* ("NI 51-102") for fiscal years beginning on or after January 1, 2004. Under NI 51-102, the maximum time permitted to file annual and interim financial statements, Management's Discussion and Analysis ("MD&A") and Annual Information Forms ("AIF") has been shortened. In addition, the instrument includes enhanced disclosure in annual and interim financial statements, MD&A and AIF. NI 51-102 also proposes to change the distribution of financial statements and MD&A from a mandatory mailing basis to an as requested basis.

OUTSTANDING SHARE DATA

On April 30, 2004, Milagro had the following securities outstanding: 41,498,802 common shares; 1,170,107 stock options with a weighted average exercise price of $0.62 per share; and 300,000 common share purchase warrants exercisable at $0.45 per share. During the first four months of 2004, 33,334 stock options were exercised at $0.71 per share.

RISKS AND UNCERTAINTIES

The business of exploring for, developing and producing oil and natural gas reserves is inherently risky. There is substantial risk that the manpower and capital employed will not result in the finding of new reserves in economic quantities. There is a risk that the sale of reserves may be delayed indefinitely due to processing constraints, lack of pipeline capacity or lack of markets. The price Milagro receives for its oil and natural gas production fluctuates continuously and, for the most part, is beyond the Company's control. Milagro is exposed to financial risks including fluctuation in interest rates and the Canadian/US dollar exchange rate. Milagro is also subject to the risks associated with owning oil and natural gas properties, including environmental risks associated with air, land and water. In all areas of our business, we compete against entities that may have greater technical and financial resources. Milagro's growth is dependent upon external sources of financing which may not be available on acceptable terms. There are numerous uncertainties in estimating Milagro's reserve base due to the complexities in estimating the magnitude and timing of future production, revenue, expenses and capital.

Milagro mitigates these risks by hiring highly qualified personnel, either directly as employees or indirectly when contracting for services. Our philosophy of focusing on a limited number of geographical areas allows us to develop a high level of technical and managerial expertise in each area. To control the cost and pace of development, we acquire high working interests in each prospect and operate wherever possible. Milagro may enter into commodity price and interest rate hedging strategies to add a degree of certainty to cash flow. We diversify our oil and natural gas marketing by using various marketers and a variety of contracts with respect to pricing and term. In the field, we adhere to sound operational standards, which meet or exceed recognized levels. Finally, Milagro maintains an insurance program consistent with industry practice to protect against destruction of assets, well blowouts, pollution and other business interruptions.

SELECTED QUARTERLY INFORMATION
(Unaudited)

	2003				2002			
	Q4	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Financial Highlights								
($000s, except per share amounts)								
Oil and gas revenue	**1,832**	**1,802**	**1,725**	**2,536**	2,112	1,228	1,039	698
Cash flow from operations	**219**	**978**	**615**	**1,283**	1,104	597	447	307
Per share – diluted	**–**	**0.03**	**0.03**	**0.05**	0.06	0.03	0.02	0.02
Net earnings (loss) (1)	**(691)**	**562**	**201**	**430**	350	117	88	56
Per share – diluted	**(0.02)**	**0.01**	**0.01**	**0.02**	0.02	–	0.01	–
Capital expenditures	**8,096**	**5,757**	**2,388**	**2,369**	3,822	2,133	890	2,083
Operating Highlights								
Average daily production volumes								
Oil and NGLs (bbl/day)	**339**	**242**	**271**	**314**	320	187	223	210
Natural gas (mcf/day)	**2,015**	**2,198**	**1,936**	**2,498**	2,630	2,169	1,226	1,022
Boe (boe/day)	**675**	**608**	**594**	**730**	758	549	428	380
Field netbacks – oil and NGLs ($/bbl)								
Selling price	**25.25**	**27.28**	**28.05**	**36.22**	28.88	32.21	31.12	22.14
Royalties	**(6.32)**	**(6.69)**	**(10.41)**	**(9.56)**	(7.85)	(7.38)	(6.71)	(3.44)
Production expenses	**(12.12)**	**(9.89)**	**(6.64)**	**(6.45)**	(5.14)	(7.78)	(4.47)	(4.84)
Field netback	**6.81**	**10.70**	**11.00**	**20.21**	15.89	17.05	19.94	13.86
Field netbacks – natural gas ($/mcf)								
Selling price	**5.63**	**5.90**	**5.86**	**6.72**	5.22	3.37	3.64	3.04
Royalties	**(0.97)**	**(0.92)**	**(1.21)**	**(1.63)**	(1.26)	(0.83)	(1.20)	(0.93)
Production expenses	**(1.26)**	**(0.96)**	**(0.60)**	**(0.57)**	(0.67)	(0.54)	(0.68)	(0.46)
Field netback	**3.40**	**4.02**	**4.05**	**4.52**	3.29	2.00	1.76	1.65
Field netbacks – equivalent unit ($/boe)								
Selling price	**29.49**	**32.19**	**31.94**	**38.55**	30.28	24.33	26.69	20.39
Royalties	**(6.06)**	**(5.99)**	**(8.71)**	**(9.68)**	(7.70)	(5.77)	(6.95)	(4.39)
Production expenses	**(9.87)**	**(7.42)**	**(5.00)**	**(4.72)**	(4.48)	(4.79)	(4.29)	(3.92)
Field netback	**13.56**	**18.78**	**18.23**	**24.15**	18.10	13.77	15.45	12.08
Corporate cash netbacks ($/boe)								
Field netback	**13.56**	**18.78**	**18.23**	**24.15**	18.10	13.77	15.45	12.08
General and administrative expenses	**(5.85)**	**(2.53)**	**(5.19)**	**(2.67)**	(1.85)	(1.67)	(3.05)	(2.61)
Financing charges	**(0.01)**	**(0.31)**	**(1.41)**	**(0.46)**	(0.42)	(0.27)	(0.92)	(0.50)
Current income and other taxes	**(4.18)**	**1.53**	**(0.24)**	**(1.52)**	–	–	–	–
Cash flow from operations	**3.52**	**17.47**	**11.39**	**19.50**	15.83	11.83	11.48	8.97
Wells Drilled								
Gross	**6**	**7**	**4**	**1**	13	6	–	5
Net	**6.0**	**7.0**	**4.0**	**1.0**	10.5	4.8	–	5.0
Undeveloped Land								
Net acres	**47,100**	**53,700**	**33,900**	**23,600**	20,800	7,200	2,000	2,000
Common Share Information								
Shares outstanding (000s)								
Weighted average during the period	**40,366**	**31,145**	**22,846**	**22,659**	20,715	19,718	16,615	16,054
Period end – basic	**41,465**	**36,909**	**22,859**	**22,659**	22,659	19,718	19,718	16,054
Period end – fully diluted	**42,969**	**38,694**	**25,194**	**25,194**	25,144	21,953	21,953	18,147

(1) Amounts for 2002 and the first three quarters of 2003 have been restated for the retroactive application of adopting CICA Handbook Section 3110, Asset Retirement Obligations in 2003.

MANAGEMENT'S REPORT TO THE SHAREHOLDERS

All of the information in this annual report is the responsibility of management. The accompanying financial statements of Milagro Energy Inc. have been prepared by management in accordance with Canadian generally accepted accounting principles. The financial information elsewhere in the annual report has been reviewed to ensure consistency in all material respects with that in the financial statements.

Milagro Energy Inc. maintains appropriate systems of internal control to give reasonable assurance that transactions are appropriately authorized, assets are safeguarded from loss or unauthorized use and financial records provide reliable and accurate information for the preparation of financial statements.

Collins Barrow Calgary LLP, an independent firm of Chartered Accountants, have been engaged to examine the financial statements and provide their Auditors' Report. Their report is presented with the financial statements. The Directors are responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Directors exercise this responsibility through the Audit Committee. This Committee, which is comprised of non-management Directors, meets with management and the external auditors to satisfy itself that management responsibilities are properly discharged and to review the financial statements before they are presented to the Directors for approval. The financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

Jeffrey C. Rekunyk
President

Michael J. Makinson
Vice President, Finance

AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the balance sheets of Milagro Energy Inc. as at December 31, 2003 and 2002 and the statements of operations and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Collins Barrow Calgary LLP

Chartered Accountants

Calgary, Alberta

March 21, 2004

BALANCE SHEETS

As at December 31	2003	2002
		(Restated – Note 2b)
Assets		
Current assets		
Accounts receivable	**$ 1,545,454**	$ 1,118,290
Property and equipment (Note 3)	**30,351,382**	14,019,324
	$ 31,896,836	$ 15,137,614
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 2,869,004**	$ 1,761,399
Bank debt (Note 4)	**1,555,579**	1,961,108
	$ 4,424,583	3,722,507
Future income taxes (Note 5)	**3,402,000**	2,770,000
Asset retirement obligations (Note 6)	**1,044,000**	622,000
	8,870,583	7,114,507
Shareholders' equity		
Share capital (Note 7)	**21,849,162**	7,366,308
Contributed surplus (Note 7)	**25,000**	7,000
Retained earnings	**1,152,091**	649,799
	23,026,253	8,023,107
	$ 31,896,836	$ 15,137,614

See accompanying notes.

On behalf of the Board of Directors

Jeffrey C. Rekunyk
Director

Robert J. Robertshaw
Director

STATEMENTS OF OPERATIONS AND RETAINED EARNINGS

Years ended December 31	2003	2002
		(Restated – Note 2b)
Revenues		
Oil and natural gas sales	$ 7,895,342	$ 5,076,970
Royalties	(1,819,097)	(1,249,310)
	6,076,245	3,827,660
Expenses		
Production	1,609,108	855,296
General and administrative	961,559	421,423
Financing charges	124,069	95,525
Depletion, depreciation and accretion	2,580,500	1,395,000
Stock-based compensation (Note 7)	18,000	7,000
	5,293,236	2,774,244
Earnings before taxes	783,009	1,053,416
Taxes (Note 5)		
Capital taxes	286,417	–
Future income taxes (recoveries)	(5,700)	442,600
	280,717	442,600
Net earnings	502,292	610,816
Retained earnings, beginning of year, as previously reported	661,199	40,383
Retroactive adjustment for change in accounting policy (Note 2)	(11,400)	(1,400)
Retained earnings, end of year	$ 1,152,091	$ 649,799
Net earnings per share (Note 9)		
Basic	$ 0.02	$ 0.03
Diluted	$ 0.02	$ 0.03

See accompanying notes.

STATEMENTS OF CASH FLOWS

Years ended December 31	2003	2002 (Restated – Note 2b)
Cash provided by (used for):		
Operations		
Net earnings	**$ 502,292**	$ 610,816
Add (deduct) items not affecting cash		
Depletion, depreciation and accretion of asset retirement obligations	**2,580,500**	1,395,000
Future income taxes (recoveries)	**(5,700)**	442,600
Stock-based compensation	**18,000**	7,000
Cash flow from operations	**3,095,092**	2,455,416
Net change in non-cash working capital (Note 8)	**680,441**	530,528
	3,775,533	2,985,944
Financing		
Issue of common shares	**16,288,554**	5,108,208
Increase (decrease) in bank debt	**(405,529)**	1,165,708
Share issue costs	**(1,168,000)**	(331,400)
	14,715,025	5,942,516
Investing		
Expenditures on property and equipment	**(18,610,558)**	(8,928,460)
Proceeds on sale of property and equipment	**120,000**	–
	(18,490,558)	(8,928,460)
Change in cash	**–**	–
Cash, beginning and end of year	**$ –**	$ –

See accompanying notes.

NOTES TO FINANCIAL STATEMENTS

For the Years Ended December 31, 2003 and 2002

Milagro Energy Inc. (the "Company") is a public company incorporated under the Business Corporations Act (Alberta) engaged in the acquisition, exploration, development and production of petroleum and natural gas reserves in western Canada.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Oil and Natural Gas Operations

Capitalized Costs

The Company follows the full cost method of accounting for oil and natural gas operations, whereby all costs of acquiring, exploring for and developing oil and natural gas reserves, are capitalized and accumulated in one cost centre. Such costs include those related to lease acquisition, geological and geophysical activities, rentals on non-producing mineral leases, drilling of productive and non–productive wells, tangible production equipment, asset retirement costs, and that portion of general and administrative expenses directly attributable to exploration and development activities. Proceeds from the disposition of oil and natural gas properties are accounted for as a reduction of capitalized costs, with no gain or loss recognized unless such disposition would alter the depletion and depreciation rate by 20 percent or more.

Depletion and Depreciation

Depletion and depreciation of oil and natural gas properties is calculated using the unit-of-production method based on production volumes, before royalties, in relation to total proved reserves as estimated by independent engineers. Natural gas volumes are converted to equivalent oil volumes based upon a relative energy content of six thousand cubic feet of natural gas to one barrel of oil. In determining costs subject to depletion, the Company includes estimated future costs to be incurred in developing proved reserves and excludes estimated salvage values. The cost of undeveloped properties are excluded from costs subject to depletion until it is determined that proved reserves are attributable to the property or impairment has occurred.

Ceiling Test

Under the full cost method of accounting, a limit is placed on the carrying amount of oil and natural gas properties. A "ceiling test" is performed to recognize and measure impairment, if any.

Impairment is recognized if the carrying amount of oil and natural gas properties, less the cost amount of undeveloped properties not subject to depletion (the "adjusted carrying amount") exceeds the estimated undiscounted future cash flows from the Company's proved reserves. The future cash flows are based on a forecast of prices and costs, as provided by an independent third party. If recognized, the magnitude of the impairment is then measured by comparing the

adjusted carrying amount to the estimated discounted future cash flows from the Company's proved and probable reserves. The future cash flows are discounted at the Company's credit-adjusted risk-free interest rate, using forecasted prices and costs.

Any impairment recognized is recorded as additional depletion and depreciation expense.

For purposes of the ceiling test, future cash flows are calculated exclusive of indirect costs such as financing charges, general and administrative expenses and income taxes.

Asset Retirement Obligations

Asset retirement obligations include the abandonment of oil and natural gas wells, dismantling and removing tangible equipment such as oil batteries and natural gas facilities, and returning the land to its original condition. The Company recognizes an asset retirement obligation ("ARO") in the period in which it is identified and a reasonable estimate of the fair value can be made. Fair value is estimated based on the present value of the estimated future cash outflows to abandon the asset, discounted at the Company's credit-adjusted risk-free interest rate. The fair value of the estimated ARO is recorded as a long-term liability with a corresponding amount capitalized to oil and natural gas properties. The amount capitalized is charged to earnings through the depletion and depreciation of oil and gas properties. The ARO liability is increased each reporting period due to the passage of time and the amount of accretion is charged to earnings. Revisions to the original estimated cost or the timing of the cash outflows may result in a change to the ARO. Actual costs incurred to settle an ARO reduce the long-term liability.

Joint Ventures

Some of the Company's exploration and production activities are conducted jointly with other companies. These financial statements reflect only the Company's proportionate interest in such activities.

(b) Depreciation

Depreciation of office equipment is provided for on a declining balance basis at a rate of 20 percent per annum.

(c) Future Income Taxes

The Company uses the liability method of accounting for income taxes. Under this method, income tax assets and liabilities are recorded to recognize future income tax inflows and outflows arising from the recovery or settlement of assets and liabilities at carrying values. Income tax assets are also recognized for the benefits from tax losses and deductions that cannot be identified with particular assets or liabilities, provided those benefits are more likely than not to be realized. Future income tax assets and liabilities are determined based on the tax laws and rates that are anticipated to apply in the period of realization.

(d) Flow-through Shares

The resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow-through share arrangements are renounced to subscribers. To recognize the foregone tax benefits to the Company, share capital is reduced and a future tax liability is recorded equal to the estimated amount of future income taxes payable.

(e) Revenue Recognition

Revenue from the sale of oil and natural gas is recognized based on volumes delivered to customers at contractual delivery points and rates. The costs associated with the delivery, including operating and maintenance costs, transportation, and production-based royalty expenses are recognized in the same period in which the related revenue is earned and recorded.

(f) Stock-based Compensation

The Company records stock-based compensation expense for stock options granted to employees, officers, directors and consultants after December 31, 2002 using the fair value method. Under this method, stock-based compensation expense is recorded over the vesting period of the option, based on the fair value of the option on the date of grant. The fair value of each option granted is estimated using the Black-Scholes option pricing model that takes into account, on the date of grant: the exercise price and expected life of the option; the price of the underlying security; the expected volatility and dividends (if any) on the underlying security; and the risk-free interest rate.

Stock-based compensation expense is recorded with a corresponding increase in contributed surplus. Consideration received on the exercise of an option, together with the amount previously charged to contributed surplus, is recorded as an increase in share capital.

The Company accounts for stock options granted to employees and directors prior to January 1, 2003 using the intrinsic value method. Under this method, no compensation expense is recognized when options are granted at prevailing market prices. Consideration received on the exercise of an option is recorded as share capital.

(g) Per Share Amounts

Basic net earnings per common share is computed by dividing net earnings by the weighted average number of common shares outstanding during the period. Diluted earnings per share is computed using the treasury stock method, whereby the effect of in-the-money instruments such as stock options or common share purchase warrants affect the calculation. The treasury stock method assumes that proceeds received from the exercise of in-the-money dilutive instruments are used to repurchase common shares at the average market price during the period.

(h) Measurement Uncertainty

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingencies. Such estimates primarily relate to unsettled transactions and events at the balance sheet date. Actual results could differ from those estimated.

The amount recorded for depletion and depreciation of oil and natural gas properties, the provision for asset retirement obligation costs and the ceiling test calculation are based on estimates of proved reserves, production rates, commodity prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be significant.

2. CHANGES IN ACCOUNTING POLICIES

(a) Full Cost Accounting

In 2003 the Company adopted CICA Accounting Guideline AcG-16 "Oil and Gas Accounting – Full Cost" which replaces AcG-5 "Full Cost Accounting in the Oil and Gas Industry". The new guideline modifies the ceiling test calculation and outlines additional disclosure requirements as provided in Note 3.

The components of the new ceiling test calculation include: undiscounted estimated future cash flows based on proved reserves and forecast prices and costs; discounted estimated future cash flows based on proved plus probable reserves and forecast prices and costs; and no reference to corporate costs such as general and administrative expenses, financing charges and taxes.

The components of the previous ceiling test calculation were: undiscounted estimated future cash flows based on proved reserves and year-end prices and costs; and an estimate of future corporate costs such as general and administrative expenses, financing charges and taxes.

There was no impact on the Company's reported financial results as a result of applying the new policy.

(b) Asset Retirement Obligations

In 2003 the Company adopted the new CICA Handbook Section 3110, "Asset Retirement Obligations". The change in the accounting policy has been applied retroactively with restatement of prior periods. The new standard requires recognition in the financial statements of the liability associated with retiring tangible long-lived assets such as oil and gas wells and related equipment. The asset retirement obligation is recognized in the period it is incurred and when a reasonable estimate of the fair value can be made.

Prior to the new standard, the Company accumulated a provision for future site restoration costs on the balance sheet that was charged to earnings on a unit-of-production method based on proved reserves. The accumulated liability on the balance sheet was reduced for actual expenditures incurred.

As a result of adopting the new standard, December 31, 2003 liabilities increased by $688,000, property and equipment increased by $778,000 and net earnings for the year then ended decreased by $14,000. Applying the new standard retroactively resulted in a decrease in 2002 net earnings of $10,000, an increase in liabilities of $535,400 and an increase in property and equipment of $524,000. Opening 2003 retained earnings decreased by $11,400 to account for the cumulative effect of the retroactive restatement for all prior years.

(c) Stock-based Compensation

In 2003 the Company elected to prospectively adopt amendments to CICA Handbook Section 3870, "Stock-based Compensation and Other Stock-based Payments", whereby stock options granted to employees, officers, directors and consultants are accounted for using the fair value method. Under this method, stock-based compensation expense is recognized when an option is granted, based on the fair value of the option on the date of grant. Prior to the adoption of the new standard, the Company accounted for the grant of stock options to employees and directors using the intrinsic value method. Under this method, no compensation expense is recorded for stock options granted at prevailing market prices.

Under the transitional provisions of the standard, the Company accounts for all stock options granted after December 31, 2002 using the fair value method while stock options granted to employees and directors during 2002 are accounted for using the intrinsic value method. The Company discloses pro forma stock-based compensation expense and pro forma net earnings that would have resulted had the fair value method been used to account for stock options granted to employees and directors during 2002.

For the year ended December 31, 2003, the adoption of the amended accounting standard resulted in a decrease in net earnings and an increase in contributed surplus of $7,000.

3. PROPERTY AND EQUIPMENT

	2003	2002
		(Restated – Note 2b)
Oil and natural gas properties	**$ 34,962,802**	$ 16,119,656
Office equipment	**145,086**	128,674
	35,107,888	16,248,330
Less accumulated depletion and depreciation	**(4,756,506)**	(2,229,006)
	$ 30,351,382	$ 14,019,324

At December 31, 2003, undeveloped property costs of $1,640,000 (2002 – $814,800) were excluded from the depletion and depreciation calculation.

During 2003, the Company capitalized $122,036 (2002 – $71,047) of general and administrative expenses relating to exploration and development activities.

The benchmark oil and natural gas selling prices used in the December 31, 2003 ceiling test calculation are as follows:

	Oil		Natural Gas	
	WTI, Cushing Oklahoma (US$/bbl)	Company Average (Cdn$/bbl)	Henry Hub (US$/mmbtu)	Company Average (Cdn$/mcf)
2004	34.25	30.85	5.70	6.41
2005	29.00	25.97	4.80	5.31
2006	27.00	24.46	4.50	4.96
2007	25.00	21.70	4.35	4.76
2008	25.00	21.70	4.35	4.76

The prices increase at rates of 1.5 to 2.0 percent per year after 2008. Adjustments were made to the benchmark prices to reflect varied delivery points and quality differentials in the products delivered.

4. BANK DEBT

	2003	2002
Revolving production loan	**$ 1,555,579**	$ 1,648,108
Specific variable rate loan	**–**	313,000
	$ 1,555,579	$ 1,961,108

The Company has a revolving demand production line of credit of $7.0 million bearing interest at a rate of bank prime plus 0.75 percent per annum. The revolving production loan is secured by a $10.0 million demand debenture that provides for a fixed and floating charge over all of the Company's present and future assets. Under the terms of this agreement, the Company is required to meet certain financial covenants.

5. INCOME TAXES

The provision for income tax differs from the result that would be obtained by applying the combined Canadian federal and provincial tax rate to earnings before taxes. The principal reasons for this difference are as follows:

	2003	2002 (Restated – Note 2b)
Corporate tax rate	**40.62%**	42.1%
Expected income tax expense	**$ 318,000**	$ 443,000
Increase (decrease) resulting from:		
Reduction in future income tax liability from change in tax rates	**(453,600)**	(15,000)
Non deductible Crown charges	**550,600**	452,500
Resource allowance	**(338,900)**	(289,800)
Alberta royalty tax deduction	**(102,500)**	(50,700)
Other	**20,700**	(97,400)
Tax provision	**$ (5,700)**	$ 442,600

The provision for capital taxes reflected in the statement of operations includes Federal large corporation tax and Saskatchewan capital taxes, which includes the Saskatchewan resource surcharge.

The following table sets forth the components of the Company's future income tax liability at December 31, 2003 and 2002:

	2003	2002
		(Restated – Note 2b)
Liability related to carrying amount of property and equipment in excess of available tax deductions	**$ 3,804,000**	$ 2,899,700
Benefit of undeducted share issuance costs	**(402,000)**	(129,700)
	$ 3,402,000	$ 2,770,000

At December 31, 2003 the Company had cumulative income tax deductions of approximately $20.6 million available to reduce future taxable income.

Corporate tax returns are subject to audit and reassessment by Canada Customs and Revenue Agency. The results of any reassessments will be accounted for in the year in which they are determined.

6. ASSET RETIREMENT OBLIGATIONS

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the asset retirement obligations associated with the retirement of oil and natural gas properties:

	2003	2002
		(Restated - Note 2b)
Balance, beginning of year	**$ 622,000**	$ 164,000
Liabilities incurred	**369,000**	408,000
Liabilities settled	–	–
Accretion expense	**53,000**	50,000
Balance, end of year	**$ 1,044,000**	$ 622,000

Total estimated future asset retirement costs of $1,863,000 (2002 – $1,224,000) have been discounted using an average credit-adjusted risk free rate of 6 percent. Most of these obligations are not expected to be paid for several years and will be funded from general company resources at the time of abandonment.

7. SHARE CAPITAL

a) Authorized

Unlimited number of common shares, no par value

Unlimited number of preferred shares, issuable in series

b) Common Shares Issued

	Number of Shares	Stated Value
Balance, December 31, 2001	16,053,685	$ 3,502,900
Private placement	3,330,500	2,497,875
Private placement of flow-through shares	2,941,177	2,500,000
Exercise of stock options	333,333	110,333
Tax benefits renounced to shareholders	–	(1,053,000)
Share issue costs, net of future income taxes of $139,600	–	(191,800)
Balance, December 31, 2002	22,658,695	$ 7,366,308
Private placements	**15,500,000**	**12,880,000**
Private placement of flow-through shares	**2,300,000**	**2,990,000**
Exercise of stock options	**706,773**	**283,554**
Exercise of warrants	**300,000**	**135,000**
Tax benefits renounced to shareholders	**–**	**(1,046,500)**
Share issue costs, net of future income taxes of $408,800	**–**	**(759,200)**
Balance, December 31, 2003	**41,465,468**	**$ 21,849,162**

c) Share Capital Offerings

In June 2002, the Company completed a private placement of 3,330,500 common shares at $0.75 per share for proceeds of $2,497,875.

In December 2002, the Company completed a private placement of 2,941,177 flow-through common shares at $0.85 per share for proceeds of $2,500,000. Income tax deductions of $2,500,000 were renounced to subscribers effective December 31, 2002 and the related estimated future tax cost of $1,053,000 was recorded as a reduction of share capital. Qualifying expenditures of approximately $1,912,500 relating to the December 31, 2002 renunciation were incurred in 2003.

In August 2003, the Company completed a private placement of 13,500,000 common shares at $0.80 per share for proceeds of $10,800,000.

In October 2003, the Company completed a private placement of 2,300,000 flow-through common shares priced at $1.30 per share and 2,000,000 common shares priced at $1.04 per share, for total proceeds of $5,070,000. Income tax deductions of $2,990,000 were renounced to subscribers effective December 31, 2003 and the related estimated future tax cost of $1,046,500 was recorded as a reduction of share capital. Qualifying expenditures of approximately $2,600,000 relating to the December 31, 2003 renunciation will be incurred in 2004.

d) Stock-based Compensation

The Company has a stock option plan that provides for the issuance of options to employees, officers, directors and consultants. Under the plan, the exercise price of options granted cannot be less than the closing market price on the day immediately preceding the date of grant. Options typically vest over a three-year period and expire five years from the date of grant. The aggregate number of shares to be issued upon exercise of all options granted under the plan may not exceed the maximum number of shares permitted under the rules of any stock exchange on which the Company's common shares are listed. As at December 31, 2003, there were 3,116,666 common shares reserved for future issuance under the plan.

A summary of the Company's stock option plan as at December 31, 2003 and 2002 and changes during the years then ended is set forth below:

	2003		2002	
	Number of Options	**Weighted Average Exercise Price**	Number of Options	Weighted Average Exercise Price
Outstanding, beginning of year	**1,885,214**	**$ 0.52**	1,453,547	$ 0.37
Granted	**125,000**	**$ 1.00**	765,000	$ 0.72
Exercised	**(706,773)**	**$ 0.40**	(333,333)	$ 0.33
Cancelled	**(100,000)**	**$ 0.71**	–	–
Outstanding, end of year	**1,203,441**	**$ 0.62**	1,885,214	$ 0.52
Exercisable at year end	**588,443**	**$ 0.51**	960,214	$ 0.39

The following table summarizes stock options outstanding at December 31, 2003:

Exercise Prices	Options Outstanding	Weighted Average Remaining Contractual Life	Options Exercisable
$0.34	240,000	2.9 years	160,000
$0.36	111,667	1.4 years	111,667
$0.50	151,774	2.6 years	125,108
$0.71	150,000	4.0 years	33,334
$0.74	475,000	3.3 years	158,334
$1.19	75,000	4.9 years	–
	1,203,441	3.2 years	588,443

Stock options granted to consultants during 2002 and all stock options granted during 2003 are accounted for using the fair value method, whereby stock-based compensation expense is recognized when an option is granted. The Company recorded stock-based compensation expense of $18,000 in 2003 (2002 - $7,000).

Options granted to employees, officers and directors during 2002 are accounted for using the "intrinsic value method" whereby no compensation expense is recorded when the stock options are granted. If the fair value method was used to account for stock options granted to employees, officers and directors in 2002, the stock-based compensation costs and the pro forma net earnings and pro forma net earnings per share would be as follows:

	2003	2002 (Restated - Note 2b)
Stock-based compensation costs ($)	**86,000**	41,000
Net earnings:		
As reported ($)	**502,292**	610,816
Pro forma ($)	**416,292**	569,816
Net earnings per share – basic:		
As reported ($ per share)	**0.02**	0.03
Pro forma ($ per share)	**0.01**	0.03
Net earnings per share – diluted:		
As reported ($ per share)	**0.02**	0.03
Pro forma ($ per share)	**0.01**	0.03

The fair value of each option granted was estimated on the date of grant using the Black-Scholes options pricing model with the following weighted average assumptions:

Year of Grant	2003	2002
Fair value of options granted ($/share)	0.50	0.40
Risk-free interest rate (%)	3.8	4.0
Expected life (years)	4	4
Expected volatility (%)	61	70
Expected dividend yield (%)	–	–

There are limitations to the Black-Scholes option valuation model as it relates to estimating the fair value of stock options granted by the Company to its employees, directors and consultants. The Black-Scholes option valuation model was developed for use in estimating the fair value of traded options that are fully transferable and have no vesting restrictions. Stock options granted under the Company's stock option plan are not transferable, cannot be traded and vest over a three-year period. Furthermore, trading in the Company's common shares by the holders of the Company's stock options is often restricted. The Black-Scholes model requires an estimate of the volatility of the underlying security. The Company uses historical trading data of its common shares to arrive at an estimate of expected volatility. Changes to the assumptions used in the Black-Scholes model may have a significant impact on the calculation and, therefore, the estimate of fair values.

e) Common Share Purchase Warrants

The Company has 300,000 (2002 – 600,000) common share purchase warrants outstanding, which are exercisable at $0.45 per share and expire on November 28, 2004.

8. SUPPLEMENTAL CASH FLOW INFORMATION

	2003	2002
Changes in non-cash working capital:		
Accounts receivable	**$ (427,164)**	$ (762,483)
Accounts payable and accrued liabilities	**1,107,605**	1,293,011
	$ 680,441	$ 530,528
Cash payments included in the statement of cash flows:		
Taxes	**$ 36,417**	$ –
Financing charges	**$ 124,069**	$ 101,425

9. PER SHARE AMOUNTS

	2003	2002
Earnings per share:		
Basic	**$ 0.02**	$ 0.03
Diluted	**$ 0.02**	$ 0.03
Weighted average number of shares outstanding:		
Basic	**29,307,384**	18,292,082
Diluted	**30,284,003**	19,021,856

For the year ended December 31, 2003, 976,619 shares were added to the weighted average number of common shares outstanding for the dilutive effect of stock options and warrants (2002 – 729,774 shares). The calculation of diluted earnings per share for 2003 does not include 75,000 stock options (2002 – 725,000 stock options), as the inclusion of these options would have been anti-dilutive.

10. FINANCIAL INSTRUMENTS

Credit Risk

A portion of the Company's accounts receivable are with joint venture partners in the oil and gas industry and are subject to normal industry credit risks. Purchasers of the Company's oil and natural gas production are subject to an internal credit review designed to minimize the risk of non-payment.

Fair Values

The Company's financial instruments included on the balance sheets as at December 31, 2003 and 2002 are comprised of accounts receivable, accounts payable and accrued liabilities and bank debt. The fair values of these financial instruments approximate their carrying value due to the short-term nature of those instruments.

11. RELATED PARTY TRANSACTIONS

A director of the Company is a partner of a law firm that provides legal services to the Company. During 2003, the Company paid a total of $104,933 (2002 – $72,948) to this firm for legal fees and disbursements, of which $12,501 is included in accounts payable and accrued liabilities at December 31, 2003 (2002 – Nil).

A director of the Company is the President and significant shareholder of a corporation that was paid $279,126 (2002 – $95,946) by the Company for well logging and perforating services. Of this amount, $49,768 is included in accounts payable and accrued liabilities at December 31, 2003 (2002 – $34,046).

A director of the Company is the President and significant shareholder of a corporation that was paid $99,793 (2002 – Nil) for pipeline construction work.

These transactions have been recorded at the exchange amount.

12. COMMITMENTS

The Company has a lease commitment for its office premises through to November 30, 2004. During 2004, the amount due under this commitment, including rent and estimated operating expenses, is $83,000.

13. COMPARATIVE FIGURES

The presentation of certain of the comparative figures has been changed to conform to the presentation adopted for the current year.

CORPORATE INFORMATION

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President, Big Guns Perforating and Logging Inc.

William C. Guinan [2][4]
Partner, Borden Ladner Gervais LLP

Michael J. Makinson [4]
Vice President, Finance, Milagro Energy Inc.

Robert J. Pritchard [1][3]
President, Taylor Gas Liquids Ltd.

Jeffrey C. Rekunyk
President, Milagro Energy Inc.

Robert J. Robertshaw [1][2][3]
President, Denim Pipeline Construction Ltd.

Notes:
(1) Member of the Audit Committee
(2) Member of the Compensation Committee
(3) Member of the Reserves Committee
(4) Member of the Corporate Governance Committee

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